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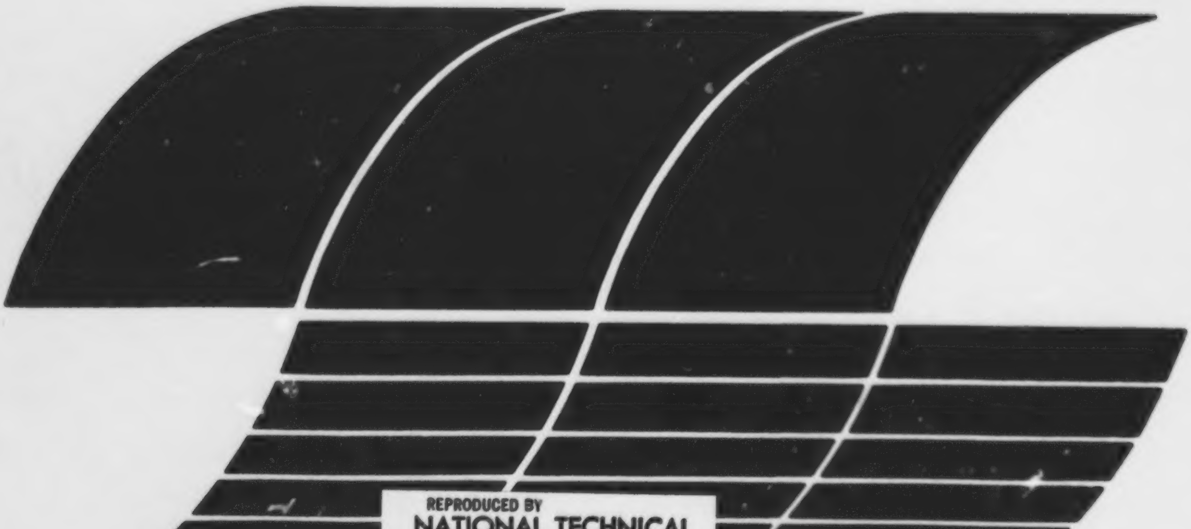

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The report gives results of testing of 10 representative coal-fired boilers in the Upper-Midwest, including an assessment of SOx, NOx, CO, unburned HC, and particulate emissions from these units, as well as an assessment of the operational impact of coal switching. The study showed that western subbituminous coals can be substituted for eastern bituminous coals as an industrial boiler fuel. Western coals are compatible with industrial coal-fired units of current design. Two unit types of older design (underfed and traveling grate stokers) experienced difficulty burning western coal. In some cases, the boiler's maximum load capcity had to be limited, a problem that can be eliminated by predrying the coal or by increasing superheat steam attemperation capacity. Western subbituminous coals were superior to eastern coals in terms of SOx, NOx, particulate, and unburned HC emissions. Western coals could be fired at lower excess air and exhibited substantially lower combustible losses than eastern coals. The size of delivered western coal was a problem in most of the stoker-fired units tested: it generally had too large a percentage of fine coal, caused by its poor weathering characteristics. Stoker performance on western coal can be improved by sizing the coal at the point of use, to reduce delivery distances to about 200 miles.

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ABSTRACT

The testing of ten representative industrial coal-fired boilers in the upper-midwest has resulted in an assessment of sulfur oxides, nitrogen oxides, carbon monoxide, unburned hydrocarbon and particulate emissions from these units as well as an assessment of the operational impact of coal switching.

This study has shown that western subbituminous coals can be substituted for eastern bituminous coals as an industrial boiler fuel. The western coals are compatible with industrial coal-fired units of current design. Two unit types of older design (underfed and traveling grate stokers) were found to experience difficulty burning western coal. Some cases have been noted where the maximum load capacity of the boiler had to be limited. This problem can be eliminated by predrying the coal or by increased superheat steam attemperation capacity.

Western subbituminous coals were found to be superior to eastern coals in terms of SO_x, NO_x, particulate, and unburned hydrocarbon emissions. The western coals could be fired at lower excess air and exhibited substantially lower combustible losses than eastern coals.

The size of delivered western coal proved to be a problem in most of the stoker-fired units tested. The coal generally had too large a percentage of fine coal resulting from the poor weathering characteristics of western coals.

Stoker performance on western coal could be improved if the coal were sized locally at the point of use so that delivery distances could be reduced to about 200 miles.

Boiler efficiencies on western coal were lower due to the high moisture content of the western coal. The reduced efficiency due to the moisture losses were somewhat offset by the lower combustible losses and lower excess oxygen (O_2) required for western coal combustion.

This study has defined the operational parameters that must be followed in order to successfully burn western coal in industrial-sized stokers and pulverized coal units. Excess O_2 and carbon monoxide monitors for combustion control would improve overall industrial boiler performance on both eastern and western coal. These controls are necessary since many times the margin of success can be as small as ± 0.5% excess O_2 in the flue. For the most part, present instrumentation does not provide sufficient precision in combustion control. Operator training and education must go hand-in-hand with improved controls for successful western coal firing.

CONTENTS

Section Page

Abstract iii
Figures vii
Tables xv
Conversion Factors xviii
Acknowledgement xx
Dedication xx

1.0 INTRODUCTION 1

2.0 CONCLUSIONS 3

- 2.1 Properties of Western Subbituminous Coals 3
- 2.2 Pulverized Coal Combustion 12
- 2.3 Stoker-Fired Boilers 25

3.0 RECOMMENDATIONS FOR FURTHER WORK 42

4.0 TEST EQUIPMENT AND PROCEDURES 43

- 4.1 Gaseous Emissions Measurements 43
- 4.2 Gaseous Emission Sampling Techniques 49
- 4.3 Sulfur Oxides Measurement and Procedure 49
- 4.4 Particulates Measurement and Procedures 52
- 4.5 Sampling and Analysis Procedure 54
- 4.6 Efficiency Evaluation 55

5.0 TEST RESULTS 57

- 5.1 Dairyland Power Cooperative, Alma, Wisconsin 57
- 5.2 Uniroyal Boiler #2 87
- 5.3 University of Wisconsin, Stout 106

Section Page

5.4 University of Wisconsin, Eau Claire 145

5.5 University of Wisconsin, Madison 169

5.6 Willmar Municipal Utilities Commission 195

5.7 Fairmont Public Utilities Commission, Unit #3, Fairmont, Minnesota 224

5.8 Waupun Central Generating Plant, Unit #3, Waupun, Wisconsin 267

5.9 St. John's Central Generating Plant Unit #2, St. John's Abbey, Collegeville, MN 291

5.10 Fremont Department of Utilities, Fremont, Nebraska 320

APPENDIX A - INDUSTRIAL-SIZED BOILER POPULATION SURVEY 347

APPENDIX B - GEOGRAPHICAL COAL SULFUR DISTRIBUTION AND IMPACT ON AIR QUALITY OF FUEL SWITCHING TO WESTERN COAL 361

APPENDIX C - DETAILED COMBUSTION REQUIREMENTS FOR SPECIFIC BOILER FIRING TYPES 373

APPENDIX D - CANDIDATE WESTERN COAL DEFINITION 395

APPENDIX E - EXAMINATION OF SUPPLY VARIABLES OF SPECIFIC WESTERN COALS 407

FIGURES

Number		Page
2-1	Nitric oxide vs. excess oxygen, Alma Unit 3, western coal.	17
2-2	Nitric oxide vs. excess oxygen, Alma Unit 3, eastern coal.	18
2-3	Nitric oxide vs. excess oxygen. Comparison of 29 kg/s four-burner PC boiler and 20.2 kg/s four-burner PC boiler.	21
2-4	Chronological display of the development of stoker-type boilers.	27
2-5	Comparison of western and eastern coal nitric oxide emissions, University of Wisconsin, Stout.	31
2-6	Comparison of western and eastern coal nitric oxide emissions, University of Wisconsin, Eau Claire.	32
2-7	Stoker firing staging limits, Willmar Unit 3, 20.2 kg/s steam, western coal.	33
2-8	Carbon monoxide vs. excess oxygen, University of Wisconsin, Madison 12.6 kg/s steam spreader stoker.	34
2-9	Percent carbon in outlet fly ash, Willmar Unit 3, 20.2 kg/s steam spreader stoker, western coal.	36
2-10	Carbon monoxide emissions vs. load, Willmar Unit 3, 20.2 kg/s steam spreader stoker, western coal.	38
2-11	Boiler efficiency comparison of pulverized coal firing to spreader stoker coal firing for a high and low moisture coal type.	40
4-1	Flow schematic of mobile flue gas monitoring laboratory.	48
4-2	Cutaway showing SO_2/SO_3 sampling probe.	50
4-3	Shell-Emeryville SO_2/SO_3 sample system.	51
4-4	Method 5 particulate sampling train.	53

FIGURES (continued)

Number		Page
5.1-1	Vertical layout of Dairyland Power Cooperative's Unit 3, Alma, Wisconsin, before installation of the electrostatic precipitator.	59
5.1-2	Sample area geometry, Dairyland Power Cooperative Unit 3.	60
5.1-3	Nitric oxide vs. oxygen, Dairyland Power Cooperative Unit 3, western coal.	66
5.1-4	Nitric oxide vs. oxygen, Dairyland Power Cooperative Unit 3, eastern coal.	67
5.1-5	Uncontrolled particulates vs. boiler load, Dairyland Power Cooperative Unit 3.	76
5.1-6	Controlled particulate emissions vs. boiler load, Dairyland Power Cooperative Unit 3.	77
5.1-7	Sulfur oxides emissions vs. boiler load, Dairyland Power Cooperative Unit 3.	80
5.1-8	Carbon monoxide emissions vs. excess oxygen, Dairyland Power Cooperative Unit 3.	82
5.1-9	Boiler efficiency vs. capacity and coal type, Dairyland Power Cooperative Unit 3.	85
5.2-1	Multiple retort underfeed stoker with link grate, Uniroyal Boiler 2.	90
5.2-2	Cross-sectional view of stoker, Uniroyal Boiler 2.	92
5.2-3	Orientation of thermocouples on grate, Uniroyal Boiler 2.	99
5.2-4	Detailed view of thermocouple installation, Uniroyal Boiler 2.	100
5.2-5	Detail of tuyere plate with orientation of thermocouple probe, Uniroyal Boiler 2.	101
5.3-1	Water-cooled vibrating grate stoker.	107
5.3-2	Front view section showing water-cooled grate.	108
5.3-3	Load vs. excess oxygen, as-found operation, Stout Boiler 2, West Kentucky coal.	114
5.3-4	Load vs. SO_x emissions, as-found operation, Stout Boiler 2, West Kentucky coal.	116

FIGURES (continued)

Number		Page
5.3-5	Excess oxygen vs. sulfur oxide emissions at various loads, Stout Boiler 2, West Kentucky coal.	118
5.3-6	Load vs. NO emissions, as-found operation, Stout Boiler 2, West Kentucky coal.	119
5.3-7	NO emissions vs. excess O_2 at various loads, Stout Boiler 2, West Kentucky coal.	120
5.3-8	Load vs. carbon monoxide emissions at as-found operation, Stout Boiler 2, West Kentucky coal.	121
5.3-9	Excess O_2 vs. carbon monoxide emissions at various loads, Stout Boiler 2, West Kentucky coal.	122
5.3-10	Particulate emissions vs. percent of rated load, as-found operation, Stout Boiler 2, West Kentucky coal.	124
5.3-11	Particulates vs. excess oxygen, Stout Boiler 2, West Kentucky coal.	125
5.3-12	Carbon monoxide emissions during grate vibration, Stout Boiler 2, Wyoming coal.	127
5.3-13	Load vs. excess oxygen, as-found operation, Stout Boiler 2, Wyoming coal.	129
5.3-14	Load vs. sulfur oxide emissions, as-found operation, Stout Boiler 2, Wyoming coal.	131
5.3-15	Excess oxygen vs. sulfur oxide emissions at various loads, Stout Boiler 2, Wyoming coal.	134
5.3-16	Load vs. NO emissions, as-found operation, Stout Boiler 2, Wyoming coal.	135
5.3-17	Excess oxygen vs. NO emissions, Stout Boiler 2, Wyoming coal.	136
5.3-18	Load vs. CO emissions, as-found operation, Stout Boiler 2, Wyoming coal.	137
5.3-19	Excess oxygen vs. CO emissions at various loads, Stout Boiler 2, Wyoming coal.	138
5.3-20	Particulates vs. load, as-found operation, Stout Boiler 2, Wyoming coal.	140
5.3-21	Particulates vs. excess oxygen, Stout Boiler 2, Wyoming coal.	141

FIGURES (continued)

Number		Page
5.4-1	Chain grate overfeed stoker.	146
5.4-2	Sample port locations in Unit 1 at University of Wisconsin, Eau Claire.	148
5.4-3	Nitric oxide emissions vs. excess O_2, University of Wisconsin, Eau Claire, eastern coal.	152
5.4-4	Nitric oxide emissions vs. excess O_2, University of Wisconsin, Eau Claire, western coal.	154
5.4-5	Nitric oxide vs. percent of rated load, University of Wisconsin, Eau Claire.	155
5.4-6	SO_x emissions vs. excess O_2, University of Wisconsin, Eau Claire.	157
5.4-7	SO_3 component of SO_x emissions, University of Wisconsin, Eau Claire.	158
5.4-8	Carbon monoxide emissions vs. excess O_2, University of Wisconsin, Eau Claire, eastern coal.	159
5.4-9	Carbon monoxide emissions vs. excess O_2, University of Wisconsin, Eau Claire, western coal.	161
5.4-10	Particulate emissions vs. excess O_2, University of Wisconsin, Eau Claire.	164
5.4-11	Particulate emissions vs. percent rated load, University of Wisconsin, Eau Claire.	165
5.4-12	Boiler efficiency vs. percent rated load, University of Wisconsin, Eau Claire.	166
5.5-1	Westinghouse Centrafire spreader stoker with traveling grate.	170
5.5-2	Excess oxygen vs. boiler load, University of Wisconsin, Madison, Unit 2, Montana Colstrip coal.	173
5.5-3	Excess oxygen vs. boiler load, University of Wisconsin, Madison, Unit 2, Illinois Stonefort coal.	174
5.5-4	Nitric oxide vs. excess oxygen, University of Wisconsin, Madison, western coal.	175
5.5-5	Nitric oxide vs. excess oxygen, University of Wisconsin, Madison, eastern coal.	176

FIGURES (continued)

Number		Page
5.5-6	Carbon monoxide vs. excess oxygen, University of Wisconsin, Madison, eastern coal.	177
5.5-7	Carbon monoxide vs. excess oxygen, University of Wisconsin, Madison, western coal.	178
5.5-8	Nitric oxide vs. boiler load, University of Wisconsin, Madison, eastern and western coals.	180
5.5-9	Particulate loading vs. boiler load, University of Wisconsin, Madison.	181
5.5-10	Feeder distribution and fuel feed drive.	185
5.5-11	Effect of spill plate position.	186
5.5-12	Boiler efficiency vs. excess O_2, University of Wisconsin, Madison.	193
5.5-13	Efficiency vs. load, University of Wisconsin, Madison.	194
5.6-1	Unit 3, Willmar Municipal Utilities Commission, Willmar, Minnesota.	196
5.6-2	Side view, inlet sampling area.	199
5.6-3	Cross section, inlet sampling duct, top view, gas flow is into paper.	200
5.6-4	Cross section, outlet sampling duct, top view, gas flow is out of paper.	201
5.6-5	Nitric oxide vs. excess oxygen, Willmar Unit 3, western coal.	209
5.6-6	Nitric oxide vs. excess oxygen, Willmar Unit 3, eastern coal.	210
5.6-7	Carbon monoxide vs. load, Willmar Unit 3, western coal.	211
5.6-8	Carbon monoxide vs. load, Willmar Unit 3, eastern coal.	212
5.6-9	Carbon vs. load, Willmar Unit 3, western coal.	214
5.6-10	Carbon vs. load, Willmar Unit 3, eastern coal.	215
5.6-11	Excess oxygen vs. load, staging limits, Willmar Unit 3, western coal.	216
5.6-12	Excess oxygen vs. load, staging limits, Willmar Unit 3, eastern coal.	217

FIGURES (continued)

Number		Page
5.7-1	Inlet sampling duct configuration, Fairmont Unit 3.	227
5.7-2	Configuration of outlet sampling probes, Fairmont Unit 3.	228
5.7-3	Schematic of coal handling system, Fairmont, Minnesota Public Utilities Commission.	237
5.7-4	Conditions under which unit was tested, Fairmont Unit 3, eastern coal.	240
5.7-5	Conditions under which unit was tested, Fairmont Unit 3, coal blend.	241
5.7-6	Inlet particulates vs. load, Fairmont Unit 3.	244
5.7-7	Outlet particulates vs. load, Fairmont Unit 3.	246
5.7-8	Cyclone efficiency vs. particulate loading, Fairmont Unit 3, eastern coal and blended coal.	247
5.7-9	Cyclone efficiency vs. load, Fairmont Unit 3.	248
5.7-10	Percent combustibles vs. load, Fairmont Unit 3.	249
5.7-11	SO_x comparison for eastern coal vs. blend, Fairmont Unit 3.	252
5.7-12	Sulfur mass balance, Fairmont Unit 3.	254
5.7-13	Nitric oxide emissions vs. excess O_2, Fairmont Unit 3, eastern coal.	256
5.7-14	Nitric oxide emissions vs. excess O_2, Fairmont Unit 3, coal blend.	257
5.7-15	Nitric oxide emissions vs. load, Fairmont Unit 3, eastern coal.	259
5.7-16	Nitric oxide emissions vs. load, Fairmont Unit 3, coal blend.	260
5.7-17	CO comparison for eastern coal vs. blend, Fairmont Unit 3.	265
5.8-1	Schematic of boilers and flue gas duct system, Waupun, Wisconsin.	269
5.8-2	Sample area geometry, Waupun Unit 3.	271
5.8-3	Photograph of a 30% d-RDF blend as fired at Waupun.	276

FIGURES (continued)

Number		Page
5.8-4	Particulates vs. fuel mixture, Waupun Unit 3.	281
5.8-5	Outlet particulates vs. boiler load, Waupun Unit 3.	282
5.8-6	Excess O_2 vs. load, Waupun Unit 3.	284
5.8-7	Carbon monoxide vs. load, Waupun Unit 3.	286
5.8-8	Nitric oxide vs. excess O_2, Waupun Unit 3.	287
5.8-9	Sulfur in fuel and grate ash vs. fuel blend, Waupun Unit 3.	288
5.9-1	Schematic of boilers and flue gas duct system, St. John's Unit 2.	295
5.9-2	Sample area geometry, St. John's Abbey Unit 2.	296
5.9-3	Western coal test conditions, St. John's Unit 2.	301
5.9-4	Eastern coal test conditions, St. John's Unit 2.	302
5.9-5	Particulates vs. load, St. John's Unit 2.	303
5.9-6	Particulate emissions vs. excess O_2, St. John's Unit 2.	304
5.9-7	Total oxides of sulfur vs. boiler load, St. John's Unit 2.	306
5.9-8	Sulfur trioxide vs. boiler load, St. John's Unit 2.	307
5.9-9	Nitric oxide vs. excess O_2, St. John's Unit 2.	309
5.9-10	Carbon monoxide vs. excess O_2, St. John's Unit 2, western coal.	310
5.9-11	Carbon monoxide vs. excess O_2, St. John's Unit 2, eastern coal.	311
5.9-12	Hydrocarbons vs. excess O_2, St. John's Unit 2, western coal.	312
5.9-13	Hydrocarbons vs. excess O_2, St. John's Unit 2, eastern coal.	313
5.9-14	Western coal ash balance (disregarding carbon analyses), test numbers arranged in order of excess O_2, St. John's Unit 2.	317
5.9-15	Eastern coal ash balance (disregarding carbon analyses), test numbers arranged in order of excess O_2, St. John's Unit 2.	318

FIGURES (continued)

Number		Page
5.10-1	Sample area geometry, Fremont Department of Utilities Unit 6.	323
5.10-2	Excess O_2 vs. boiler load, test parameters, Fremont Department of Utilities Unit 6.	326
5.10-3	Uncontrolled particulate emissions vs. boiler load, Fremont Department of Utilities Unit 6.	330
5.10-4	Controlled particulate emissions vs. boiler load, Fremont Department of Utilities Unit 6.	331
5.10-5	Multiclone dust collector efficiency vs. boiler load, Fremont Department of Utilities Unit 6.	333
5.10-6	Sulfur oxide emissions vs. boiler load, Fremont Department of Utilities Unit 6.	335
5.10-7	Sulfur balance, Fremont Department of Utilities Unit 6.	336
5.10-8	Nitric oxide emissions vs. boiler load, Fremont Department of Utilities Unit 6.	339
5.10-9	Nitric oxide emissions vs. excess oxygen, Fremont Department of Utilities Unit 6.	340
5.10-10	Carbon monoxide emissions vs. excess oxygen at three boiler loads, Fremont Department of Utilities Unit 6, Walden Colorado coal.	342
5.10-11	Boiler efficiency vs. excess O_2, Fremont Department of Utilities Unit 6.	345

TABLES

Number		Page
2-1	Fuel and Mineral Analyses for All Coals Tested	4
2-2	Some Specific Western Coal Problems	9
2-3	Design Type of Units Tested and Overall Performance on Eastern and Western Coals	10
2-4	Screen Analyses of Pulverized Coal	14
2-5	Coal Performance Comparison, Alma Unit 3	15
2-6	Impact on NO Emissions Due to Fuel Switching from Eastern Bituminous to Western Subbituminous Coals	20
2-7	SO_x Emission Comparison for Western and Eastern Coals	23
2-8	Particulate Emissions Data for All Coals Tested	24
2-9	Comparison of HC Emissions from Eastern and Western Coals	35
5.1-1	Coal Analysis Summary, Unit #3, Dairyland Power Cooperative, Alma, Wisconsin	61
5.1-2	Screen Analyses of Pulverized Coal	63
5.1-3	Effect of Varying Air Registers	64
5.1-4	Effect of Varying Diffuser Position	65
5.1-5	Effect of Excess Oxygen	68
5.1-6	Effect of Staged Combustion	69
5.1-7	Emission Data Summary, Unit 3, Dairyland Power Cooperative, Alma, Wisconsin	70
5.1-8	Average Particulate and Fuel Ash Data	75
5.1-9	Sulfur Balance Summary, Unit 3, Dairyland Power Cooperative, Alma, Wisconsin	78
5.1-10	Relation of Fuel Nitrogen to Nitric Oxide Emissions	79

Number Page

5.1-11 Boiler Efficiency Summary, Dairyland Power Cooperative, Unit 3, Alma, Wisconsin 83

5.2-1 Characteristics of Coals Fired in Uniroyal Boiler #2 97

5.2-2 Thermocouple Readings of Grate Metal Temperatures at Uniroyal Boiler #2, Eau Claire, Wisconsin 102

5.3-1 Comparison of Test Coals Fired at Stout Boiler #2 111

5.3-2 Emission Data Summary, University of Wisconsin, Stout Boiler #2 113

5.3-3 SO_x Data Summary, University of Wisconsin, Stout Boiler #2 West Kentucky Coal 117

5.3-4 Sulfur Oxides Emissions Summary, University of Wisconsin, Stout Boiler #2, Wyoming Coal 132

5.4-1 Fuel Analysis - Base Coal, West Kentucky - Vogue 149

5.4-2 Fuel Analysis - Test Coal, Wyoming, Bighorn 149

5.4-3 Emission Data Summary - University of Wisconsin, Eau Claire 151

5.4-4 Comparison of SO_x Emissions for Similar Load Ranges 156

5.4-5 Particulate Emissions Data Summary for Eau Claire 162

5.5-1 Emission Data Summary, University of Wisconsin, Madison, Unit 2 172

5.5-2 SO_x Data Summary University of Wisconsin, Madison, Unit 2 182

5.5-3 Comparison of Boiler Efficiency on Eastern and Western Coal 187

5.5-4 Calculation of Efficiency 189

5.6-1 Emission Summary, Willmar Unit 3 205

5.6-2 Calculation of Efficiency 218

5.6-3 Flue Gas Distribution Before and After Stoker Readjustment 223

Number		Page
5.7-1	Comparison of Test Coals at Fairmont Unit 3	230
5.7-2	Gaseous Emissions Summary, Fairmont Public Utilities Commission, Unit 3	242
5.7-3	Sulfur Oxides Data, Fairmont Public Utilities Commission, Unit 3	251
5.7-4	Sulfur Oxides Retention in Ash, Fairmont Public Utilities Commission, Unit 3	253
5.7-5	Nitric Oxide Data, Fairmont Public Utilities Commission, Unit 3	255
5.7-6	Boiler Efficiency Data, Fairmont Public Utilities Commission, Unit 3	261
5.8-1	Comparison of Test Fuels Fired at Waupun Unit 3	273
5.8-2	Fuel Mixing Schedule, Waupun Unit 3	274
5.8-3	Operating Variables, Waupun Unit 3	279
5.8-4	Particulate Emissions from Waupun Unit 3	280
5.8-5	Gaseous Emissions, Waupun Unit 3	283
5.8-6	Sulfur Oxides Balance, Waupun Unit 3	289
5.9-1	Comparison of Test Coals, St. John's Unit 2	292
5.9-2	Gaseous Emission Summary, St. John's Unit 2	299
5.9-3	Sulfur Balance Comparison for Two Fuels, St. John's Unit 2	305
5.9-4	Ash Balance Data, St. John's Unit 2	316
5.10-1	Comparison of Test Coals	321
5.10-2	Emission Data Summary, Fremont Department of Utilities, Unit 6	328
5.10-3	Sulfur Balance Summary, Fremont Department of Utilities, Unit 6	329
5.10-4	Emissions Summary for Special Tests, Fremont Department of Utilities, Unit 6	338
5.10-5	Boiler Efficiency Summary, Fremont Department of Utilities, Unit 6	343

CONVERSION FACTORS

SI Units to Metric or English Units

To Obtain	From	Multiply By
g/Mcal	ng/J	0.004186
10^6 Btu	GJ	0.948
Btu	gm cal	3.9685×10^{-3}
lb/10^6 Btu	ng/J	0.00233
ft	m	3.281
in.	cm	0.3937
ft^2	m^2	10.764
ft^3	m^3	35.314
lb	kg	2.205
Fahrenheit	Celsius	$t_F = 9/5(t_C) + 32$
Fahrenheit	Kelvin	$t_F = 1.8t_K - 460$
psig	Pa	$P_{psig} = (P_{pa})(1.450 \times 10^{-4}) - 14.7$
psia	Pa	$P_{psia} = (P_{pa})(1.450 \times 10^{-4})$
iwg (39.2 °F)	Pa	$P_{iwg} = (P_{pa})(4.014 \times 10^{-3})$
10^6 Btu/hr	MW	3.413
GJ/hr	MW	3.60

To Obtain ppm at 3% O_2 of	Multiply* Concentration in ng/J by
Natural Gas Fuel	
CO	3.23
HC	5.65
NO or NO_x	1.96
SO_2 or SO_x	1.41
Oil Fuel	
CO	2.93
HC	5.13
NO or NO_x	1.78
SO_2 or SO_x	1.28
Coal Fuel	
CO	2.69
HC	4.69
NO or NO_x	1.64
SO_2 or SO_x	1.18

*These conversions depend on fuel composition. The values given are for typical fuels.

English and Metric Units to SI Units

To Obtain	From	Multiply By
ng/J	$lb/10^6$ Btu	430
ng/J	g/Mcal	239
GJ	10^6 Btu	1.055
m	ft	0.3048
cm	in.	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
kg	lb	0.4536
Celsius	Fahrenheit	$t_c = 5/9\ (t_F - 32)$
Kelvin	Fahrenheit	$t_K = 5/9\ (t_F - 32) + 273$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895x10^3)$
Pa	psia	$P_{pa} = (P_{psia})(6.895x10^3)$
Pa	iwg (39.2 °F)	$P_{pa} = (P_{iwg})(249.1)$
MW	10^6 Btu/hr	0.293
MW	GJ/hr	0.278

To Obtain ng/J of	Multiply* Concentration in ppm @ 3% O_2 by
Natural Gas Fuel	
CO	0.310
HC	0.177
NO or NO_x (as NO_2)	0.510
SO_2 or SO_x	0.709
Oil Fuel	
CO	0.341
HC	0.195
NO or NO_x (as NO_2)	0.561
SO_2 or SO_x	0.780
Coal Fuel	
CO	0.372
HC	0.213
NO or NO_x (as NO_2)	0.611
SO_2 or SO_x	0.850

*These conversions depend on fuel composition.
The values given are for typical fuels.

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The authors would like to express their appreciation to Mr. David G. Lachapelle for his support and understanding throughout this program.

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DEDICATION

The authors would like to dedicate this report to the memory of the late Mr. Donald Mattimore whose generosity and cooperation to a large degree made this program possible.

SECTION 1.0

INTRODUCTION

Faced with the problem of complying with sulfur dioxide control regulations, electric utilities and industries in the Midwest have been increasing their use of low-sulfur western coal. The extent to which Midwestern demand for western coal will continue to increase depends on a number of factors. Foremost among these are: (1) the evolution of federal, state, and local sulfur dioxide control regulations, (2) the growth of coal as a boiler fuel, and (3) the cost of western coal relative to the costs of alternate fuels and control technologies.

The upper Midwest region (Minnesota, Wisconsin, Iowa, Nebraska, and Illinois) is presently the only area where low-sulfur western sub-bituminous coal is cost competetive with midwestern and eastern coals. Within this region, there is considerable variation with regard to western coal use versus the traditional eastern supply. This variability is due in part to equipment limitations which dictate that a certain coal be burned.

For this reason it is necessary to determine the operational compatibility of western coal with existing industrial coal-fired equipment, if fuel substitution is to be considered a viable sulfur oxides control strategy.

The purpose of this program, the test results of which are detailed in this report, was to assess the effectiveness of the use of lower sulfur western coals as a means of reducing sulfur oxides emissions from industrial-sized boilers in the size range 1.25 to 31.4 kg/s (10,000 to 250,000 lb/hr). The impact of SO_x, NO_x, CO, particulates, and unburned hydrocarbons emissions has been assessed as a consequence of this fuel conversion.

The scope of the testing program included testing ten representative types of coal-fired industrial boilers for a period of one month each on eastern and western coal. During this testing period, the pollutant emissions listed above were measured both in a baseline configuration and in an optimized firing mode. Operational problems of the unit were characterized for each coal. Potential reductions of pollutant emissions have been estimated for each unit type and each coal tested.

In addition to the regular comparison testing of eastern and western coals, two special test series were performed. A thorough characterization of blended eastern and western coal was performed. Also a short study of a densified refuse derived fuel (d-RDF) blended with western coal was done to demonstrate the feasibility of resource recovery as a fuel source for the industrial market.

The format of this report is as follows:

- present the general overall conclusions and recommendations of this study
- outline the testing procedure
- boiler-by-boiler description of the testing, detailing all of the emissions results and operational problems encountered

Appendices A-E contain the results of several tasks that were completed before the field testing began. Appendix A summarizes the American Boiler Manufacturers Association sales data for the years 1965-1974. These data were used as a basis for boiler selection. Appendix B contains an analysis of the impact on sulfur emissions by switching to western coals. The detailed combustion requirements for specific coal fired industrial boilers are described in Appendix C. Appendix D contains information on western coal reserves that could potentially be produced as a boiler fuel. Appendix E examines the variables associated with bringing these western coals to the market place.

A Final Report Supplement will soon be available. This Supplement will contain results of an examination of the data from this study with emphasis on exploiting the sulfur retention characteristics of the ash from western coals.

SECTION 2.0

CONCLUSIONS

2.1 PROPERTIES OF WESTERN SUBBITUMINOUS COALS

A large supply of low sulfur, subbituminous coal exists in the Powder River region of Wyoming and the Fort Union region of southeast Montana. This coal is being mined at a rapidly increasing rate. One mine in Wyoming, for example, increased production from 0.81 million metric tons per year in 1973 to 3.0 million metric tons per year in 1974, a factor of 3.7 in only one year. However, the most impressive statistics are the reserve capacity of these western coal fields. That same mine in Wyoming whose production increased so dramatically in 1974 has a reserve capacity of 16.8 billion metric tons. This translates to a lifetime of 50 years at current production rates. The large reserves, coupled with the relative ease of strip mining, point to a ready supply of coal for fuel if other constraints are met. One of these constraints is the subject of this report.

The compatibility of these western subbituminous coals with existing industrial boilers could be a hinderance to their wide acceptance as a boiler fuel. The compatibility of coal and boiler are determined both by coal properties and boiler design. Since the boiler designs are fixed in existing units, the coal properties are the variables of interest.

Western coal characteristics are those of a typical subbituminous coal: an ash-free higher heating value of 19 to 24 MJ/kg (8,200 to 10,500 moist Btu/lb), and a high moisture content of 20% to 30%. The ash content of most of these coals is less than 10% by weight. The western subbituminous coals exhibit high volatile to fixed carbon ratios, typically approaching a value of one. The coals tested during this study are presented in Table 2-1. The mineral analysis is also included for selected coals. The sequence number keys the ultimate analysis with the mineral analysis.

TABLE 2-1. FUEL AND MINERAL ANALYSES FOR ALL COALS TESTED

				Proximate Analysis(%)		Ultimate Analysis (Percent) As Received										Sulfur Forms, Percent As Received		
Seq. No.	Test No.	Coal Type	Test Location	Volatiles	Fixed Carbon	Ash	Moisture	Sulfur	Hydrogen	Carbon	Nitrogen	Oxygen (diff)	Chlorine	AFT(H=W) °K (°F)	As Recd MJ/kg (Btu/lb)	Pyrite	Sulfate	Organic
1	9	W. Kentucky	Alma	—	—	14.49	7.46	3.68	4.24	59.87	1.09	9.07	0.10	1431 (2115)	25.013 (10,754)	1.21	0.05	2.42
2	6	"	"	22.32	60.00	16.00	1.68	3.71										
3	16	"	"	17.58	61.20	19.02	2.20	3.33										
4	55	"	"	16.45	55.08	16.39	12.08	4.32										
5	57	Montana	"	24.14	47.00	12.63	16.24	1.74							21.783 (9,365)			
6	73	"	"	35.09	36.30	10.67	17.94	0.86	5.34	57.26	0.79	7.14	0	1361 (1990)	21.864 (9,400)	0.53	0.07	0.26
7	74	"	"	33.71	36.80	36.80	11.56	0.84										
8	75	"	"	31.78	37.70	11.19	19.33	0.84							21.632 (9,300)			
9	76	"	"	31.55	38.30	11.36	18.09	3.79							21.981 (9,450)			
10	78	"	"	31.87	38.06	12.32	17.75	0.78							21.588 (9,290)			
11	4	Wyoming	U/W Stout	34.19	43.33	4.68	17.80	0.83							24.139 (10,378)			
12	14	"	"			3.92	21.53	0.83	4.13	56.76	0.91	11.91	0.01	1431 (2115)	23.030 (9,901)	0.11	0.02	0.70
13	15	"	"	32.82	41.69	7.06	18.43	1.23							23.044 (9,907)			
14	19	W. Kentucky	"	34.39	49.48	7.11	9.02	3.41							27.977 (12,028)			
15	27	"	"	33.95	57.13	0.50	9.47	2.60							27.954 (12,018)			
16	31	"	"			7.25	4.49	2.81	5.03	71.36	1.28	7.78	0	1467 (2180)	30.180 (12,975)	1.39	0.06	1.36
17	36	Wyoming	"	39.83	41.61	4.88	13.68	0.82							24.525 (10,544)			
18	4	"	U/W E.C.	32.41	40.31	5.44	21.84	0.62							21.932 (9,429)			
19	7	"	"			5.13	20.16	0.72	4.01	57.98	1.10	10.90	0	1428 (2110)	23.439 (10,077)	0.35	0.02	0.35
20	10	"	"	34.40	38.60	8.22	18.78	0.84							21.220 (9,123)			

(continued)

TABLE 2-1 (continued).

Seq. No.	Test No.	Coal Type	Test Location	Proximate Analysis (%) Vola-tiles	Proximate Analysis (%) Fixed Carbon	Ultimate Analysis (Percent) As Received Ash	Moisture	Sulfur	Hydrogen	Carbon	Nitrogen	Oxygen (diff)	Chlorine	AFT(H=W) °K (°F)	As Recd MJ/kg (Btu/lb)	Sulfur Forms, Percent As Received Pyrite	Sulfate	Organic
21	11	W. Kentucky	U/W E.C.	37.09	48.19	6.86	7.86	3.02							28.698 (12,338)			
22	20	"	"	38.24	48.03	6.31	7.42	2.80							28.905 (12,427)			
23	30	"	"			8.03	9.15	2.79	4.60	65.05	1.24	9.13	0.01	1414 (2085)	27.186 (11,688)	0.94	0.27	1.58
24	2	Montana	U/W Mad.	32.06	39.65	8.26	20.03	1.05							21.985 (9,452)			
25	5	"	"			8.29	25.28	0.73	3.35	51.09	0.78	10.45	0.03	1514 (2265)	20.246 (8,704)	0.39	0.00	0.34
26	7	"	"	29.57	37.66	7.99	24.78	0.93							20.459 (8,796)			
27	10	"	"	30.46	36.26	8.95	24.33	1.26							20.557 (8,838)			
28	11	W. Kentucky	"	37.19	45.60	8.79	8.42	2.94							27.705 (11,911)			
29	14	"	"			9.60	7.37	3.07	4.62	66.32	1.30	7.71	0.01	1467 (2180)	27.926 (12,006)	1.59	0.15	1.34
30	15	"	"	38.98	46.23	7.98	6.81	3.23							29.110 (12,515)			
31	19	"	"	36.28	44.65	9.20	9.87	2.93							27.286 (11,731)			
32	8	Montana	Willmar			9.12	25.56	1.15	3.31	49.32	0.68	10.85	0.01	1486 (2215)	19.557 (8,408)	0.89	0.04	0.22
33	34	Illinois	"			7.76	7.11	2.28	4.73	69.26	1.37	7.47	0.02	1461 (2170)	29.047 (12,488)	1.09	0.07	1.12
34	3	So. Illinois	Fairmont			8.35	8.55	2.56	4.55	67.96	1.35	6.67	0.01	1481 (2205)	28.517 (12,260)	1.33	0.09	1.14
35	5	"	"	35.03	49.88	8.24	6.85	2.51							28.938 (12,441)			
36	7	"	"	33.44	51.37	8.07	7.12	1.89	4.57	68.73	0.77	8.76	0.09	1533 (2300)	28.652 (12,318)	0.76	0.11	1.02
37	9	"	"	34.42	50.31	7.48	7.79	2.06							28.873 (12,413)			
38	10	"	"	35.53	50.33	7.88	6.27	2.01							29.201 (12,554)			

(continued)

TABLE 2-1 (continued).

Seq. No.	Test No.	Coal Type	Test Location	Proximate Analysis (%)		Ultimate Analysis (Percent) As Received								AFT(H=W) °K (°F)	As Recd MJ/kg (Btu/lb)	Sulfur Forms, Percent As Received		
				Vola-tiles	Fixed Carbon	Ash	Mois-ture	Sulfur	Hydro-gen	Carbon	Nitro-gen	Oxygen (diff)	Chlor-ine			Pyrite	Sulfate	Organic
39	12	Blend	Fairmont	31.73	46.39	7.69	14.19	1.49	4.21	62.28	0.48	9.62	0.04	1472 (2190)	25.405 (10,922)	0.51	0.12	0.86
40	15	"	"	32.24	46.30	7.73	13.83	1.49							25.514 (10,969)			
41	17	"	"	31.64	47.32	8.47	12.57	1.70							25.912 (11,140)			
42	18	"	"	31.78	46.65	7.68	13.89	1.69							25.030 (10,761)			
43	--	Pure West	"	31.11	34.36	11.95	22.58	0.80	3.10	48.38	0.63	12.54	0.02	1633 (2480)	18.489 (7,949)	0.41	0.07	0.32
44	8	Western	St. Johns	37.52	41.57	5.14	15.77	0.61	4.26	59.95	0.81	13.45	0.01	1439 (2130)	24.458 (10,515)	0.24	0.00	0.37
45	16	Eastern	St. Johns	35.58	53.95	5.29	5.18	0.58	5.17	72.26	0.95	10.54	0.03	1592 (2405)	30.524 (13,123)	0.09	0.00	0.49
46	2	Montana/RDF	Waupun	30.60	36.43	7.81	25.16	0.60	3.61	50.96	0.43	11.42	0.01	1497 (2235)	20.139 (8,658)	0.46	0.01	0.13
47	--	Montana	"	35.44	43.13	10.55	10.88	0.93	3.86	58.16	0.48	15.13	0.01	1439 (2130)	22.774 (9,791)	0.50	0.13	0.30
48	--	RDF	"	54.34	10.84	30.49	4.33	0.22	4.59	34.31	0.57	24.95	0.54	1381 (2025)	14.330 (6,161)	--	0.00	--
49	3	Wyoming(Hana)	Fremont	35.40	45.43	8.83	10.34	1.39										
50	4	" "	"	33.46	45.38	9.19	11.97	1.48	4.38	61.63	1.25	10.07	0.03		25.328 (10,889)			
51	5	" "	"	34.43	45.67	8.89	11.01	1.38							25.893 (11,132)			
52	6	" "	"	33.99	44.59	6.61	14.81	0.99							24.346 (10,467)			
53	7	" "	"	35.26	42.44	6.71	15.59	0.96							24.223 (10,414)			
54	--	W. Kentucky	Uniroyal	37.00	40.50	5.76	9.0	2.50	4.81	68.21	1.26	8.46	<0.01	1441 (2133)	28.377 (12,200)			
55	--	Wyoming	"	32.36	38.49	5.30	23.85	0.61	4.07	53.75	1.01	11.41	<0.01	1428 (2110)	22.097 (9,500)			
56	9	Colorado	Fremont	35.83	43.36	7.91	12.90	0.27							24.407 (10,493)			
57	11	"	"	36.71	42.78	7.78	12.73	0.29							24.181 (10,396)			

(continued)

TABLE 2-1 (continued).

Seq. No.	Test No.	Coal Type	Test Location	Proximate Analysis (%)		Ultimate Analysis (Percent) As Received								AFT(H=W) °K (°F)	As Recd MJ/kg (Btu/lb)	Sulfur Forms, Percent As Received		
				Vola-tiles	Fixed Carbon	Ash	Mois-ture	Sulfur	Hydro-gen	Carbon	Nitro-gen	Oxygen (diff)	Chlor-ine			Pyrite	Sulfate	Organic
58	14	Colorado	Fremont	40.26	39.79	6.82	13.13	0.33							24.621 (10,585)			
59	16	"	"	35.24	45.02	6.89	12.85	0.32	4.31	61.59	0.93	13.08	0.03		24.984 (10,741)			

Seq. No.	MINERAL ANALYSIS (Percent Weight) Ignited Basis											Gronhovd's Prediction (Percent)	Actual (Measured) Fuel Sulfur Emitted (Percent)
	Phosphorus pentoxide P_2O_5	Silica SiO_2	Ferric oxide Fe_2O_3	Alumina Al_2O_3	Titania TiO_2	Lime CaO	Magnesia MgO	Sulfur trioxide SO_3	Potassium oxide K_2O	Sodium oxide Na_2O	Undeter-mined		
1	0.22	49.28	18.06	18.15	0.93	5.30	0.90	3.91	1.97	1.08	0.20	105	92
6	--	33.38	11.55	31.91	1.01	11.55	2.57	--	0.60	7.4	0.03		
12	0.59	29.82	8.18	16.42	1.05	17.15	4.80	17.48	0.68	2.98	0.85	92	78
16	0.11	45.77	25.81	20.25	1.17	1.50	0.78	1.30	2.23	0.38	0.70	109	106
19	0.40	35.40	11.71	18.00	1.10	12.00	3.00	14.40	1.22	1.61	0.16	99.5	81
23	0.12	37.38	37.16	16.87	0.93	2.30	0.75	2.23	1.76	0.42	0.08	108	91
25	0.18	39.41	6.87	18.58	0.86	14.60	3.00	14.41	0.58	0.62	0.89	99.36	91
29	0.11	45.78	25.04	21.00	1.08	1.80	0.75	1.10	2.12	0.42	0.80	109	79
32	0.19	36.47	13.40	17.25	0.81	12.40	3.00	14.54	0.48	0.52	0.94	100.3	88
33	0.23	47.30	20.65	22.50	1.22	2.50	0.81	1.92	2.36	0.38	0.13	108	109
34	0.21	46.54	24.26	21.38	1.05	1.50	0.75	0.86	2.30	0.48	0.67	109	
36	0.20	52.33	14.19	22.50	1.20	2.80	1.13	2.81	2.37	0.32	0.15	108	118
39	0.30	45.42	12.28	22.35	1.00	5.80	2.28	8.75	1.48	0.32	0.02	106	113
43	0.20	24.87	4.39	12.15	0.48	44.00	3.12	9.12	0.53	0.22	0.92	64	
44	1.09	35.19	6.36	18.89	1.15	14.85	4.36	14.20	0.66	2.28	0.97	97	95
45	0.43	50.23	8.11	28.60	2.03	3.60	1.47	4.18	1.13	0.71	0.49	108	
46	0.14	38.66	5.31	18.83	0.76	15.40	4.96	14.40	0.58	0.55	0.41	99	
47	0.16	33.42	7.76	16.24	0.71	20.20	4.32	15.26	0.48	0.52	0.93	93	28
48	0.70	59.41	5.88	9.07	1.05	11.67	1.66	2.23	1.95	6.04	0.34	89	
49	0.38	48.27	12.15	20.85	0.77	6.77	2.16	6.65	1.52	0.28	0.20	106	93
50	0.11	50.08	13.74	19.24	0.80	7.50	1.92	4.15	1.61	0.48	0.37	105	87
51	0.36	47.54	12.68	18.91	0.86	7.72	2.38	7.34	1.57	0.41	0.23	104	107
52	0.21	61.43	10.48	15.02	0.61	4.70	1.90	3.70	1.48	0.42	0.05	106	95
53	0.15	62.90	11.62	13.37	0.64	4.27	1.80	3.02	1.44	0.34	0.44	106	87
56	0.48	56.58	3.33	30.41	1.30	5.72	0.53	6.04	0.28	0.50	0.83	107	113

The western subbituminous coals are also classed as "free-burning" coals. In the free-burning coals, the pieces do not fuse together, but burn separately or, after fusion, the mass breaks up quickly into fragments. This characteristic causes problems in certain types of stokers where there is inadequate control of undergrate air distribution. Some specific western coal problems for five types of combustion devices, and the property that causes these problems, are presented in Table 2-2.

The high moisture content of the western coals causes the greatest combustion difficulty in industrial-sized equipment. In most units with superheaters, it leads to high steam superheat temperatures. It also causes flame stability problems in pulverized coal combustion and ignition problems in stoker-fired units. To recover the lost steam capacity, some pre-drying of western coals will be necessary for firing in units designed for eastern coal.

The second major problem with western coal is the size distribution of the delivered coal. Most western coals do not travel or weather well. The coal has a tendency to break into fine sizes while in transit. Therefore, even if the coal has been sized before shipment, the as-received coal will exhibit a change in size distribution toward the smaller sizes. This shift becomes more severe with longer transit and/or storage periods. The effect of this coal property on stoker unit performance is discussed below.

This paper is divided into a discussion of pulverized coal firing and stoker firing of both eastern and western coal. A general overview of boiler performance is presented in Table 2-3. Here, the units tested are rated in terms of emissions, efficiency, and overall ease of operation. The type and source of the coals tested are also given for each boiler.

TABLE 2-2. SOME SPECIFIC WESTERN COAL PROBLEMS

		COMBUSTION DEVICES							
	PROPERTIES	VIBRATING GRATE STOKER	SPREADER STOKER	PULVERIZER	UNDERFED STOKER	OVERFED STOKER	TRANSPORTATION	STORAGE	ASH COLLECTION/ DISPOSAL
COAL	Low Heating Value		o Flame stability o Reduced capacity	o Reduced capacity o High maintenance	o Reduced capacity	o Reduced capacity	o Lower Btu's/ ton-mile	o Increased equipment loading	o More ash/Btu
	High Moisture	o Ignition problems	o High superheat temperature	o Flame stability o High superheat temperature o Poor grinding	o Poor ignition o Nonuniform bed thickness	o Poor ignition	o Freezing	o Fires	o More ash/Btu
	Low Sulfur								o Inefficient precipitators
	Dustiness/ Fineness	o Uneven fuel bed	o Poor grate coverage o Overheating of grates	o Feeder plugging	o Uneven fuel bed with uncovered grate areas	o Carbon carryover o Undergrate air restriction	o Coal loss o Fugitive dust	o Fires o Fugitive dust	
	Friability		o Ash pit fires		o Ash pit fires	o Ash pit fires			
ASH	Free Burning	o Uncovered grate			o Uncovered grate	o Uncovered grate			
	Slaking/ Weathering						o Coal size degradation	o Coal size degradation	
	Sodium and Calcium		o Increased fouling	o Fouling o Sintering					o Caking

TABLE 2-3. DESIGN TYPE OF UNITS TESTED AND OVERALL PERFORMANCE ON EASTERN AND WESTERN COALS

Type of Unit Tested	Overall Performance Rating Per Coal				Comments	Eastern / Western
	Good	Fair	Poor	Unacceptable		
PULVERIZED COAL (Riley) o 28.9 kg/s (230x10^3 lb/hr) o Four Burner Face-Fired o Two Ball Tube Mill Pulverizers o UOP ESP Dairyland Power Cooperative Alma, WI	Eastern and Western				Reduced maximum capacity	Western Kentucky (River King) Montana Sarpy Creek (Westmoreland)
UNDERFED STOKER (Westinghouse) o Multiple Retort o 12.6 kg/s (100x10^3 lb/hr) o Cyclone Dust Collector Uniroyal Eau Claire, WI		Eastern		Western	Specially sized western coal was used for the test, however, the unit would not respond to load demand. Modifications are necessary to undergrate air system in order to burn western coal.	Kentucky and Illinois Wyoming (Big Horn)
VIBRATING GRATE STOKER (Detroit) o Water-Cooled Grate o 5.7 kg/s (45x10^3 lb/hr) o FD Fan/Natural ID o Cinder Trap Partic. Removal University of Wisconsin, Stout	Eastern	Western			Improved coal sizing would improve performance	Western Kentucky (Vogue) Wyoming (Big Horn)
TRAVELING GRATE STOKER (LaClede) o 7.6 kg/s (60x10^3 lb/hr) o FD Fan/Natural ID o No Particulate Controls University of Wisconsin, Eau Claire	Eastern		Western		Severely affected by coal size	Western Kentucky (Vogue) Wyoming (Big Horn)
SPREADER STOKER (Westinghouse) o 12.6 kg/s (100x10^3 lb/hr) o Traveling Grate o FD and ID Fans o Superheat, Economizer University of Wisconsin, Madison	Western and Eastern				Able to maintain full load on western coal	Kentucky (Vogue) Montana (Colstrip)

(continued)

TABLE 2-3 (continued).

Type of Unit Tested	Overall Performance Rating Per Coal				Comments	Eastern	Western
	Good	Fair	Poor	Unacceptable			
SPREADER STOKER (Detroit) o 20.2 kg/s (160x10^3 lb/hr) o Traveling Grate o Multiclone Cyclone o FD and ID Fans o Superheat, Economizer and Air Heater Willmar Municipal Utilities Willmar, MN		Western	Eastern		Maximum load reduced to 16.4 kg/s (130x10^3 lb/hr) steam on western coal due to high superheat temperatures. Large carbon losses on eastern coal--smoking.	Southern Illinois	Montana (Colstrip)
SPREADER STOKER (Erie City) o 10.1 kg/s (80x10^3 lb/hr) o Traveling Grate o FD and ID Fans o Superheat Fairmont Public Utilities Commission Fairmont, MN	Eastern	Blend			Blending problem due to fines in western coal.	So. Illinois (Sahara)	Blend 2/3 So. Ill. and 1/3 Montana (Colstrip)
SPREADER STOKER (Wickes) o 3.8 kg/s (30x10^3 lb/hr) o Traveling Grate o FD and ID Fans o Superheat o Cyclone Dust Collector Waupun Central Generating Plant Waupun, WI	Western				No problems with western coal.	- - - -	Montana
SPREADER STOKER (Keeler) o 1.7 kg/s (13x10^3 lb/hr) o Dumping Grate o FD Fan and Natural ID o No Particulate Controls St. John's Abbey Collegeville, MN	Western and Eastern				Western coal used all the time with no problems.	Unknown	Wyoming (Big Horn)
PULVERIZED COAL (B&W) o 20.2 kg/s (160x10^3 lb/hr) o 4-Burner Front-Fired o Ball and Race Pulverizers o Cyclone Dust Collector Fremont Department of Utilities Fremont, NB	Eastern (Bitumin.) and Western (Subbitumin)				Both the bituminous and the subbituminous coals performed well on this unit.	Colorado (Walden)	Wyoming (Hana)

2.2 PULVERIZED COAL COMBUSTION

One of the two pulverized coal-fired boilers tested was Unit No. 3 at Dairyland Power Cooperative at the Alma, Wisconsin generating station. This four-burner face-fired unit manufactured by Riley Stoker Corporation is rated at 29 kg/s (230,000 lb/hr) steam flow. The coal is pulverized with two ball tube mills, one mill for the upper two burners and one for the lower two burners. The unit is equipped with a spray steam attemperator. Fly ash collection is accomplished with a UOP-designed cold-side electrostatic precipitator (ESP).

The two fuels used during the testing were:

Western Kentucky Coal

- 4% sulfur
- 16% ash
- 24 MJ/kg (10,500 Btu/lb)
- 18% volatiles

and

Montana Coal

- 0.77% sulfur
- 12% ash
- 19.5 MJ/kg (8,400 Btu/lb)
- 37% volatiles

2.2.1 Boiler Performance - Alma Unit No. 3

The boiler performed well on both coals, although the unit was limited in maximum load due to excessive superheat steam temperature on the Montana coal. The steam attemperation system was not adequate to reduce the temperature to the desired 755 °K (900 °F) level at loads above 22 kg/s (174,000 lb/hr) steam on western coal. This compares to a maximum load of 25.7 kg/s (204,000 lb/hr) steam on eastern coal. The boiler is design rated at 29 kg/s (230,000 lb/hr) steam, however, this load is no longer achieved.

The primary factor causing the excessive steam temperature is the high moisture content of the coal. The water reduces the flame temperature which in turn reduces the radiant heat flux to the water walls, resulting in lower steam generation. This lower heat transfer (a function of temperature to the fourth power) removes less heat in the radiant section; however, the gas still contains a large enthalpy which then acts on a decreased amount of steam in the convective section, resulting in increased steam temperatures. The water in the fuel also results in greater gas flows which increase heat transfer rates in the convective pass.

The excessive steam temperature problem is a function of boiler design. For example, a boiler designed for western coal might not be able to make design steam temperature on eastern coal.

Increased steam attemperation would result in full capacity operation on western coal.

2.2.2 Pulverizing Mill Performance

Eastern coking coals, when exposed to furnace temperatures, will swell and form lightweight, porous coke particles. These may float out of the furnace before they are completely burned. As a result, carbon loss will be high unless pulverization is very fine. Free-burning (western) coals, on the other hand, do not require the same degree of fineness because the swelling characteristic is absent.

High volatile (western) coals ignite more readily than those with a low volatile content. Therefore, they do not require the same degree of fine pulverization. With the exception of anthracite, however, the low-volatile coals are softer, and therefore have a higher grindability. As a result, mill capacity is greater at increased fineness than with high volatile coals (Ref. 2-1).

Table 2-4 shows the screen analyses and the loads of the coal burned in tests 9, 16, 57, 63, 75, and 78. Tests 9 and 16 were on eastern coal. Test 16 was with one mill out of two operating so the load in the mill was

TABLE 2-4. SCREEN ANALYSES OF PULVERIZED COAL

	EASTERN		WESTERN				
Test No.	9	16	57	63	73	75	78
Load kg/s	15.8	6.6	21.4	16.5	11.8	20.2	13.9
10^3 lb/hr	125	52	170	131	94	160	110
- 80 mesh, %	0.65	1.00	2.90	1.40	0.65	8.74	1.53
- 80 +100 mesh, %	0.75	1.00	2.30	1.30	2.32	7.70	2.23
-100 +140 mesh, %	2.75	3.35	20.65	4.05	8.91	21.65	6.60
-140 +200 mesh, %	6.95	8.20	34.60	8.30	32.26	16.75	17.46
-200 mesh, %	88.90	86.45	39.55	84.95	55.66	45.15	72.18
Moisture, %	5.15	2.20	22.05	12.75	17.94	19.33	17.75

the same as it would have been with both mills operating at 13.1 kg/s (104,000 lb/hr) steam. The screen analyses of tests 16 and 78 may then be compared. It is seen that the western coal did not grind quite as well as the eastern coal. However in the opinion of de Lorenzi (Ref. 2-1), free-burning coals need not be ground as finely as coking coals, and this was not thought to be a severe problem. An equally important factor in mill grinding capacity is moisture. From Reference 2-1, frequently too much emphasis is placed on grindability, while other factors such as moisture, which also affect mill capacity, are almost entirely overlooked. The capacity of a pulverizer is not directly proportional to the grindability of a coal. Correction must be made for variation in fineness and moisture content.

Without quantitative analysis, it can be seen in Table 2-4 that the moisture content of test 78 is a factor of eight times higher than test 16. The grindability of the other tests tend to follow the moisture content. Test 57 with the highest moisture content exhibited the poorest grindability, followed by tests 75, 73, 78, and 63 in order of increasing grindability.

The poorly pulverized coal burns more slowly resulting in lowered heat transfer in the near-flame region (radiant section) and increased heat transfer to the convective section. At high loads (tests 57 and 75), the poor grind probably contributed to the excessive superheat steam temperature problem.

2.2.3 Emissions From Alma Unit 3

A coal performance comparison for Alma Unit 3 is presented in Table 2-5. In this table, western coal (test 66), is compared to eastern coal (test 9).

Significant differences in coal performance are noted for:

- SO_x emissions
- NO emissions
- Carbon carryover
- Uncontrolled particulate emissions
- Unit efficiency

TABLE 2-5. COAL PERFORMANCE COMPARISON
ALMA UNIT NO. 3

Coal Test No.	Western 66 (ESP Inlet)	Eastern 9 (ESP Inlet)
Load, kg/s (10^3 lb/hr)	7.4 (130)	7.4 (130)
Excess O_2, %	3.4	3.4
SO_x at 3% O_2, ppm	996	3283
NO, dry at 3% O_2, ppm	372*	490†
CO, at 3% O_2, ppm	31	21
Particulate§, ng/J (lb/MBtu)	2266 (5.28)	3411 (7.947)
ESP Efficiency, %	99.6	99.6
Carbon Carryover, % by wt	0.55	4.13
Unburned HC, at 3% O_2, ppm	25	31
Boiler Efficiency, %	85	88.5

*223 ng/J (0.52 lb/MBtu)
†296 ng/J (0.69 lb/MBtu)
§Uncontrolled

For the first four items, the western coal performed better than the eastern coal. Sulfur oxides emissions were reduced by a factor of 3 by substituting western coal. At the same time nitric oxide emissions were reduced 24% and carbon carryover was virtually eliminated. Uncontrolled particulate loadings were reduced 33%. The performance of the ESP was not affected by the fuel switch. It continued to operate at 99+% efficiency. Carbon monoxide and unburned hydrocarbon emissions were generally less than 100 ppm each. In the optimum furnace configuration, these emissions are controlled by excess air. Below 3% excess O_2 in the flue gas, these emissions became significant. Soot formation, resulting in a "black stack" was also a problem below 3% excess O_2. However, boiler efficiency was lower on western coal due to high moisture losses resulting from fuel-contained water.

Nitric Oxide

Figure 2-1 is a plot of nitric oxide as a function of excess O_2 in the flue for western coal at four loads. Figure 2-2 contains the same type data for the base eastern coal. Both figures show increasing NO with increasing O_2 at a constant load; however, the absolute magnitude of NO emissions from western coal is less at any given load and O_2 level. Most of the NO data on Figure 2-1 fall below the EPA limit for new coal-fired units of 301 ng/J (0.7 lb of NO_x as NO_2 per million Btu or about 500 ppm). Attempts to reduce the NO emissions of the eastern coal to these same (less than 500 ppm) levels resulted in high CO emissions.

Included in the factors that influence NO emissions are:

- Flame temperature
- Fuel nitrogen
- Excess oxygen

All three of these influence NO emissions when switching to western coal. The temperature of the western coal flame is lower than the eastern due to the high moisture content of the coal resulting in lower NO emissions from atmospheric nitrogen fixation and to a lesser extent fuel nitrogen conversion. In general the western coal could be fired at lower excess air before combustible losses became a problem. This is due to the higher ratio of the volatile matter

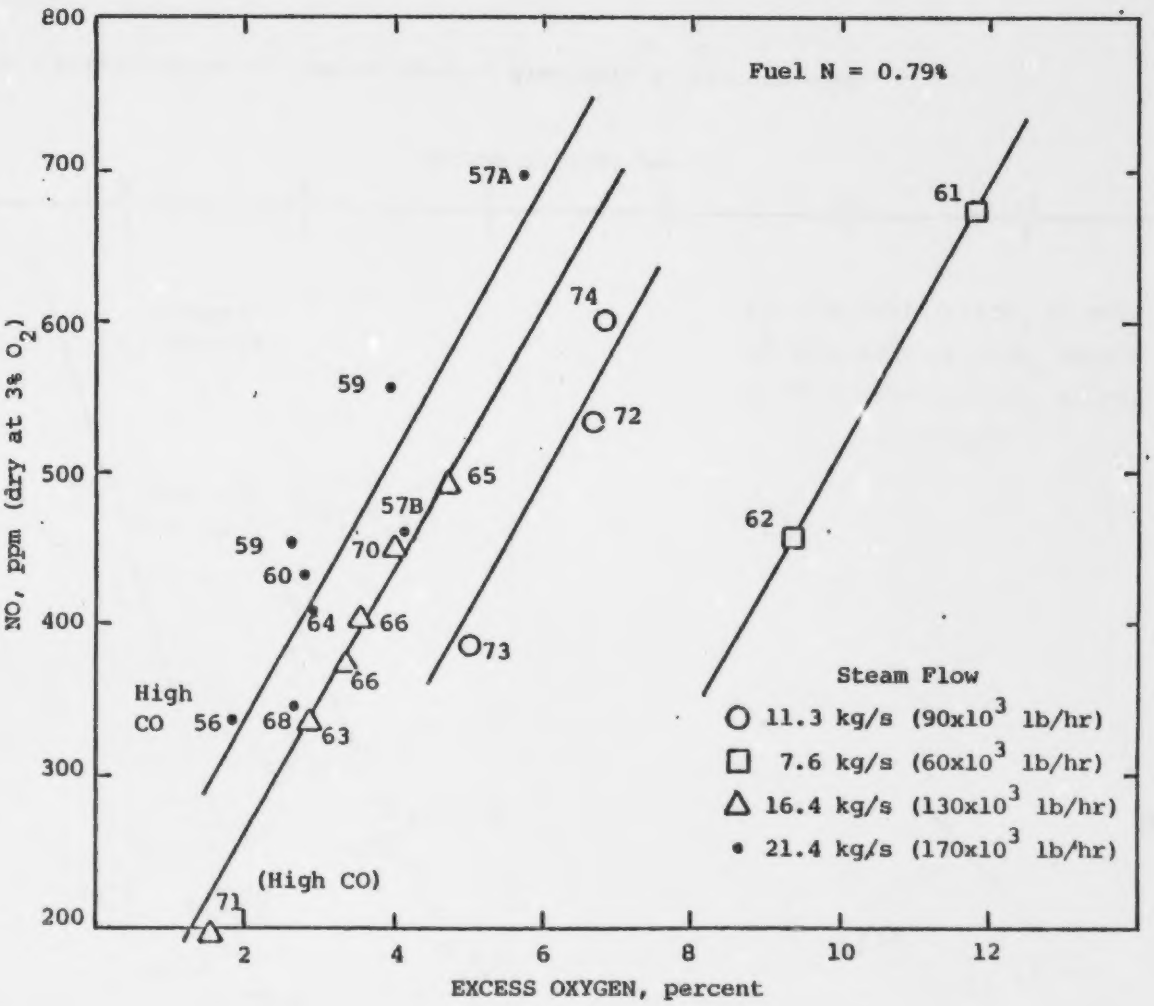


Figure 2-1. Nitric oxide vs. excess oxygen, Alma Unit 3, western coal.

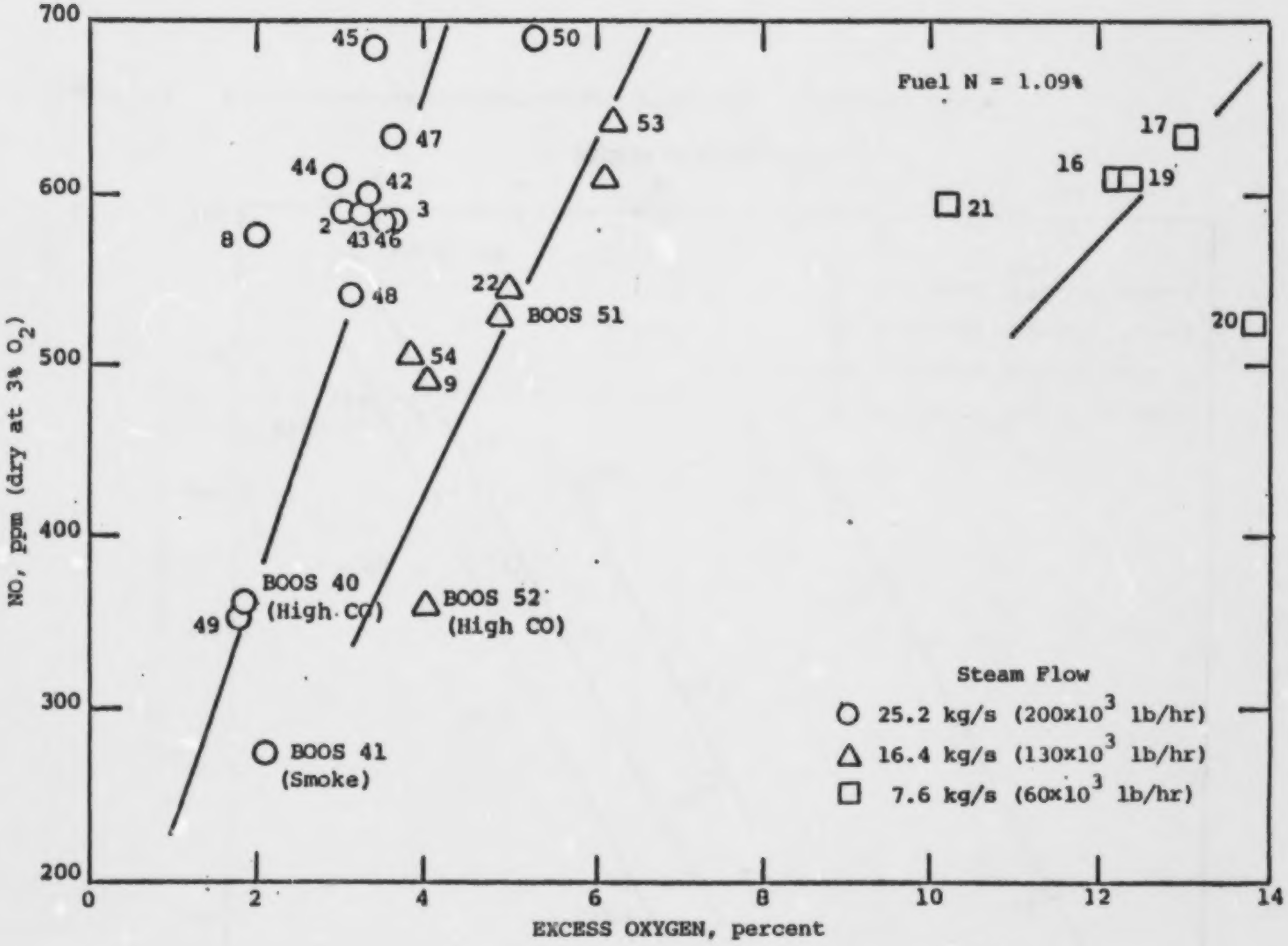


Figure 2-2. Nitric oxide vs. excess oxygen, Alma Unit 3, eastern coal.

to fixed carbon content of the western coal which results in less solid carbon to be burned out in the post-flame gases. The lower excess air requirements result in lower NO emissions.

Table 2-6 contains data for all coals tested which show that the fuel nitrogen content of the western coal is generally lower than eastern coal. In any case, not all of the fuel nitrogen present in coal is converted to nitric oxide. Typically, only 40% to 60% is converted with the amount dependent on coal type, fuel nitrogen content, the structure of the nitrogen-containing molecule within the coal, and firing conditions.

The substitution of western coal for eastern coal results in an 9% reduction in NO emissions on the average. The western coals used in this comparison had 18% less fuel-bound nitrogen than the eastern coals. The emission comparisons were based on western and eastern coal tests at comparable loads and excess O_2 levels. Since NO_x arises from both conversion of fuel-bound nitrogen and fixation of atmospheric nitrogen, it is difficult to draw any correlation between fuel nitrogen content and NO_x emissions. This is further influenced by the fact that different coals have different types of nitrogen-containing molecules which, depending on their structure, are more or less easily oxidized to NO in the flame.

The conversion of fuel nitrogen to NO is a function of the structure and distribution of the nitrogen-containing molecules within the coal. For example, under certain conditions it could be important if the nitrogen containing molecules are associated with the volatile fraction of the coal rather than the fixed carbon portion. The chemical oxidation state of the nitrogen species in coal is important since nitrogen that is partially oxidized will be more easily converted to NO. For example, azide groups ($N \equiv N$) will more readily be reduced to N_2 than $-NH_3$ groups which will be more easily oxidized to NO under flame conditions.

Figure 2-3 compares the NO emission behavior as a function of excess O_2 for three western coals on two pulverized coal units. The Fremont data were taken on a 20.2 kg/s steam flow (160,000 lb/hr) four-burner boiler while the Alma data came from a 29 kg/s steam flow (230,000 lb/hr) four-burner unit.

TABLE 2-6. IMPACT ON NO EMISSIONS DUE TO FUEL SWITCHING FROM EASTERN BITUMINOUS TO WESTERN SUBBITUMINOUS COALS

Test Site (Boiler Type)	Coal Type	Load		Percent O_2	Fuel Nitrogen		NO dry at 3% O_2		NO Change Due to Fuel Switch (E to W)	
		Mg/hr	10^3 lb/hr		Percent	ng NO/J (lb NO/MBtu)	ppm	ng NO/J (lb NO/MBtu)	ng NO/J (lb NO/MBtu)	Percent
Alma (PC)	E W. Kentucky (River King)	91	200	5.2	1.09	934 (2.17)	690	262 (0.610)	+7 (+0.015)	+2.6
	W Montana (Sarpy Creek)	77	170	5.7	0.73	779 (1.81)	695	269 (0.625)		
Fremont (PC)	W Wyoming (Hanna)	46	101	4.4	1.25	1059 (2.46)	515	196 (0.456)	-60 (-0.132)	-30.6*
	W Colorado (Walden)	49	109	4.4	0.93	800 (1.86)	369	139 (0.324)		
Eau Claire (VG)	E W. Kentucky	11	25	10.1	1.24	921 (2.14)	300	115 (0.268)	-47 (-0.110)	-40.9
	W Wyoming (Bighorn)	11	25	9.8	1.10	1076 (2.50)	178	68 (0.158)		
Willmar (SS)	E So. Illinois (Stonefort)	50	110	6.6	1.37	1016 (2.36)	375	146 (0.340)	-2 (-0.004)	-1.4
	W Montana (Colstrip)	50	111	6.6	0.68	745 (1.73)	324	144 (0.336)		
Madison (SS)	E W. Kentucky (Vogue)	41	90	7.3	1.30	998 (2.32)	379	146 (0.340)	+26 (+0.06)	+17.8
	W Montana (Colstrip)	41	90	7.2	0.78	826 (1.92)	446	172 (0.40)		
Fairmont (SS)	E So. Illinois (Sahara)	27.2	60	6.5	1.35	1013 (2.36)	282	108 (2.53)	-1 (-0.004)	-0.9
	Blend -1/3 Montana (Colstrip) 2/3 So. Illinois	28.1	62	7.0	0.48	403 (0.94)	278	107 (0.249)		
St. Johns (SS)	Unknown	3.8	8.4	15.6	0.95	667 (1.55)	413	153 (0.355)	-48 (-0.110)	-31.4
	W Wyoming (Bighorn)	3.9	8.7	15.2	0.81	710 (1.65)	281	105 (0.245)		
									Average	-9

* Not included in average

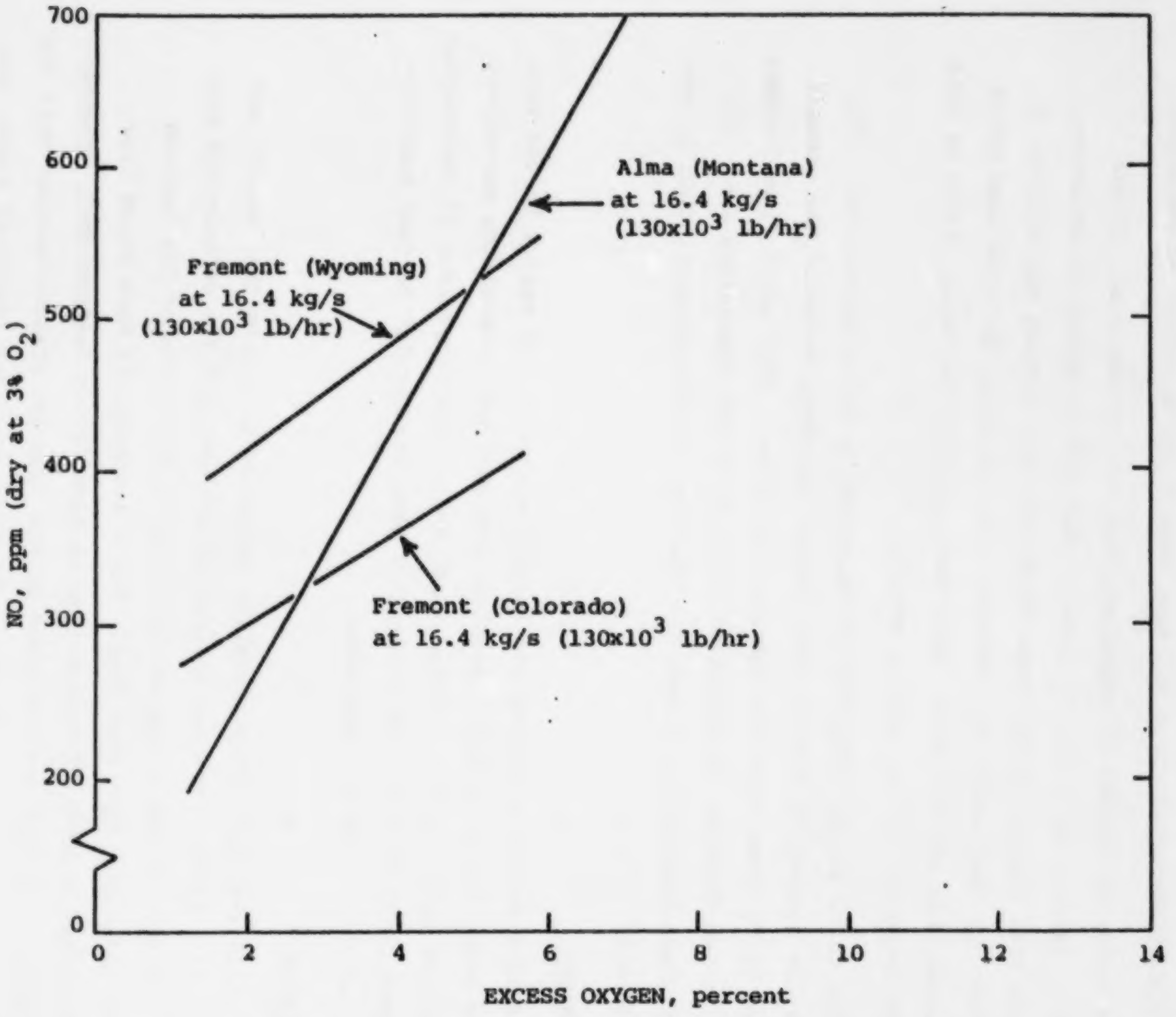


Figure 2-3. Nitric oxide vs. excess oxygen. Comparison of 29 kg/s ($230x10^3$ lb/hr) four-burner PC boiler and 20.2 kg/s ($160×10^3$ lb/hr) four-burner PC boiler.

These data indicate that the NO emissions are unit-dependent as well as coal-dependent. Furnace volume, burner heat release rate, burner spacing, and fuel/air mixing characteristics all have been found to affect NO emissions.

In order to control CO emissions from the eastern coal, it was necessary to operate at higher O_2 levels; this led to higher NO emissions. For western coal firing, it has been shown that the furnace can operate at lower excess O_2, thus lower NO. Western coal typically contains less bound fuel nitrogen than eastern coal. This fuel nitrogen can be as little as half the amount found in typical eastern coals.

The third factor affecting NO emissions is flame temperature. The high moisture content of western coal causes the temperature of the western coal flame to be lower than the eastern coal flame. This lower flame temperature lowers the fixation of molecular nitrogen in the combustion air. The effect of flame temperature lowers the fixation of molecular nitrogen in the combustion air.

Sulfur Oxides

Sulfur oxides emissions are largely a function of sulfur in the fuel. There has been some work that indicates that coal ash composition may affect the amount of sulfur oxides emitted (Ref. 2-2). The comparison of the eastern and western coals at Alma (see Table 2-7) show the benefit of fuel substitution in the control of SO_x emissions.

Particulates

Table 2-8 contains particulate emissions data from the eastern and western coals tested. The ash content of the coal and the combustible content of the fly ash emissions are given for a comparison of the maximum potential emissions from each coal. For a 4-burner, 29 kg/s steam flow (230,000 lb/hr) pulverized coal boiler at Alma firing eastern coal, approximately 60% of the coal ash was found in the flue gas stream; whereas only 40% of the western coal ash was found in the flue gas under identical firing conditions and for coals with the same ash content. Electrostatic precipitator efficiencies were unimpaired by the fuel switch. Combustible losses were higher on eastern coal than on western coal. A 34% reduction in uncontrolled particulate emissions was realized by switching to western coal.

TABLE 2-7. SO_x EMISSION COMPARISON FOR WESTERN AND EASTERN COALS

Test Site	Coal Source (Mine)	Average Fuel Sulfur		Average SO_2 Emissions		Fuel Sulfur Emitted percent
		percent	ng/J (lb $SO_2/10^6$ Btu Fired)	ppm	ng/J (lb $SO_2/10^6$ Btu Fired)	
	Western Coal					
Alma	Montana (Sarpy Creek)	0.96	880 (2.05)	791	649 (1.51)	73.8
Stout	Wyoming (Bighorn)	0.96	822 (1.92)	681	559 (1.30)	69.6
Madison	Montana (Colstrip)	0.99	949 (2.21)	1044	858 (2.00)	90.4
Willmar	Montana (Colstrip)	1.15	1174 (2.74)	934	766 (1.79)	65.3
Eau Claire	Wyoming (Bighorn)	0.73	657 (1.53)	695	570 (1.33)	86.8
St. Johns	Wyoming (Bighorn)	0.61	498 (1.16)	592	486 (1.13)	97.5
Fremont	Wyoming (Hana-Rosebud)	1.38	957 (2.23)	1053	864 (2.01)	90.3
Fremont	Colorado (Walden)	0.38	263 (0.61)	235	193 (0.45)	73.4
	Overall Average		775 (1.81)		618 (1.44)	79.8
	Eastern Coal					
Alma	Kentucky (River King)	3.57	2800 (6.64)	3036	2491 (5.81)	87.0
Stout	Kentucky (Vogue, Seam 2)	2.94	2043 (4.76)	2129	1747 (4.07)	85.5
Willmar	So. Illinois (Stonefort)	2.28	1567 (3.65)	1815	1489 (3.47)	94.0
Eau Claire	W. Kentucky (Vogue)	2.87	1803 (4.72)	2363	1939 (4.52)	95.0
Madison	W. Kentucky (Vogue)	3.04	2167 (5.05)	2378	1952 (4.55)	90.0
Fairmont	So. Illinois (Sahara)	2.13	1471 (3.43)	1628	1336 (3.11)	89.7
	Overall Average		2021 (4.71)		1826 (4.25)	90.4

Average SO_x reduction based on flue gas emission measurements = 1206 ng/J (2.81 lb $SO_2/10^6$ Btu) = 66.1%

Average SO_x reduction based on fuel analysis = 1244 ng/J (2.90 lb $SO_2/10^6$ Btu) = 61.7%

TABLE 2-8. PARTICULATE EMISSIONS DATA FOR ALL COALS TESTED

Test Site (Unit Type)	WESTERN COAL							EASTERN COAL							Change percent
	Test No.	Coal Type	Fuel Ash ng/J (lb/MBtu)	Emissions ng/J (lb/MBtu) Uncon-trolled	Emissions ng/J (lb/MBtu) Con-trolled	Combus-tion Content percent	Emission - Combustion / Fuel Ash percent	Test No.	Coal Type	Fuel Ash ng/J (lb/MBtu)	Emissions ng/J (lb/MBtu) Uncon-trolled	Emissions ng/J (lb/MBtu) Con-trolled	Combus-tion Content percent	Emission - Combustion / Fuel Ash percent	
Alma (PC)	66	Montana	5,781 (13.47)	2,266 (5.28)	9 (0.0214)	0.55	39	9	W. Kentucky	5,781 (13.47)	3,411 (7.947)	8 (0.0184)	4.13	59	-34
Eau Claire (TGS)	5	Wyoming	2,476 (5.767)	104 (0.2414)	--	---	4	28	W. Kentucky	2,949 (6.87)	150 (0.3504)	--	---	--	-31
Madison (SS/TC)	6	Montana	4,088 (9.52)	742 (1.73)	--	28	23	14	W. Kentucky	3,432 (7.996)	738 (1.72)	--	50	22	+0.6
St. Johns (SS/DG)	2	Wyoming	2,098 (4.888)	192 (0.446)	--	---	9	11	Unknown	1,730 (4.031)	617 (1.435)	--	---	--	-69
Fremont (PC)	5	Wyoming* (Hana)	3,429 (7.986)	1,545 (3.6)	420 (0.978)	---	45								
	9	Colorado*	3,235 (7.538)	1,605 (3.74)	313 (0.729)	---	50								
Willmar (SS/TG)	8	Montana	4,655 (10.847)	---	303 (0.705)	20	--	34	So.Illinois	2,667 (6.32)	--	329 (0.765)	28	--	- 8
Stout (VG)	34	Wyoming	1,986 (4.628)	97 (0.2263)	--	---	5	33	W. Kentucky	2,537 (5.911)	2,715 (0.6412)	--	---	11	-65
Fairmont (SS/TG)	17	1/3 Wstn + 2/3 Estn	3,263 (7.603)	914 (2.13)	212 (0.495)	---	28	9	So.Illinois	2,586 (6.026)	1,133 (2.64)	176 (0.409)	3.25	44	-19
AVERAGE			3,478 (8.104)	719 (1.676)	175 (0.407)					3,098 (7.22)	1,054 (2.46)	170 (0.397)		34	-32

*Not included in averages

A 4-burner, 20.2 kg/s steam flow (160,000 lb/hr) pulverized coal unit was tested at Fremont, Nebraska, on a Wyoming subbituminous coal and a Colorado subbituminous coal. Again the Wyoming coal with a higher ash content had less fly ash in the flue gas than the Colorado coal. However, the cyclone dust collector efficiency was reduced to 72% on the Wyoming coal from 80.5% on the Colorado which resulted in 108 ng/J (0.25 lb/MBtu) greater controlled particulate emissions.

2.3 STOKER-FIRED BOILERS

Coal firing of industrial boilers can be separated into two broad classes-suspension firing and grate firing.

Suspension firing is normally applied in larger sized units, however, units as small as 4.4 kg/s (35,000 lb/hr) steam flow have been built for pulverized coal firing. Current economics indicate a break-even point in the 25.2 to 31.5 kg/s (200,000 to 250,000 lb/hr) steam flow range. Suspension firing includes both pulverized coal firing (70% through a 200 mesh screen) and cyclone firing (crushed to 6.35 mm (1/4") with about 10% through a 200 mesh screen).

Grate firing comprises three general stoker types:

- Underfed
- Overfed
- Spreader

Within these three types, there are a number of variations in feed methods and grate design. Stoker-fired boilers have been built covering the entire capacity range of this study: 1.3 to 31.5 kg/s (10,000 to 250,000 lb/hr) steam flow. The present stoker-fired boiler population represents a highly individualized array of equipment.

Table 2-3, presented previously, lists stoker types tested in this study. From this assortment of units, the emissions and operating characteristics of western coal firing have been determined.

2.3.1 Operational Characteristics of Western Coals in Stokers

A chronological display of the development of the various stoker types would appear as shown in Figure 2-4.

Two properties of western subbituminous coals result in operational problems for stoker-fired units. They are:

- Coal weathering - resulting in size reduction
- "Free burning" characteristic - resulting in an uncovered grate

Many older underfed and traveling grate stokers were manufactured with insufficient control of the undergrate air to use western coal as a fuel. The problem is manifested when a dark spot of unburned coal develops on the grate. This patch of coal can grow into a large clinker if special measures are not taken to remove it. The "black patches" occur because there is insufficient local air pressure under the patch to maintain vigorous burning. The loss of local air pressure occurs because some other portion of the grate, in the same plenum control area, has become thin or bare and allows the combustion air to pass through easily. These units were designed for an eastern coal that formed some coke while burning and in turn maintained even coverage of the grate. The free-burning western coals, on the other hand, tend to form a fine powdery ash which either blows off or falls through the grate, leaving it bare. This problem is compounded by the serious size reduction that occurs while the western coal is in transit. The small coal particles burn more rapidly when there is available air. However, when there is insufficient air they tend to plug the grate and fuel-bed openings and form dark patches which turn into clinkers.

The older underfed and overfed stokers designed for eastern coal will require modifications to the undergrate air chamber to allow finer control of the air distribution, if western coals are to be used.

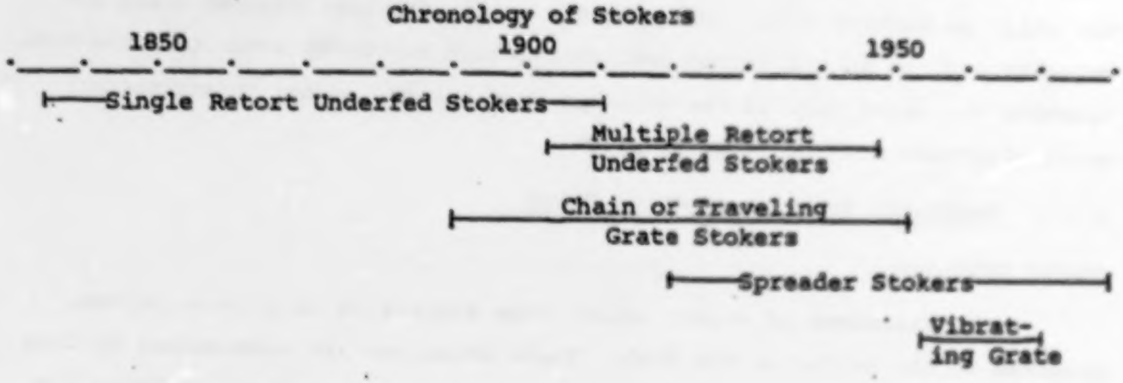


Figure 2-4. Chronological display of the development of stoker-type boilers.

Spreader stokers are affected by the same coal properties but to a lesser extent since approximately half of the combustion takes place in suspension. This suspension burning reduces the number of "fines" that reach the grate. However, the fines in the coal tend to burn close to the spreader, sometimes flashing back into the feeder opening. This flash-back mode can be dangerous since there is the possibility of a fire in the coal feeder. Coke and slag also have a tendency to build up on the spill plates and rotor blades if the flash back is allowed to persist. This problem can be alleviated somewhat by rotor speed and spill plate adjustments.

The western coal performed well in the spreader stoker units. However, some units designed for eastern coal, the maximum attainable load was about 80% while on western coal. This was due to insufficient induced draft fan capacity and, as in pulverized coal units, high superheat steam temperatures. Removing the major part of the moisture from the coal prior to combustion would alleviate both of these problems.

2.3.2 Emissions From Stoker-Fired Units

Sulfur Oxides--

The emissions of sulfur oxides from stokers is to a large degree, governed by the sulfur in the fuel. These emissions are independent of load and excess air in the flue gas. Table 2-7, presented earlier, contains the results of a SO_x emission comparison for all the coals tested in this study. The overall average SO_x emissions from actual operating industrial type boilers decreases from 1826 ng/J (4.25 lb/MBtu) on eastern coal to 618 ng/J (1.44 lb/MBtu) on western coal, or 66%. This is to be compared to the reduction as calculated from the fuel analysis from 2025 ng/J (4.71 lb/MBtu) on eastern to 778 ng/J (1.81 lb/MBtu) on western coal, or 62%. The sulfur content of the fuel was calculated from analyses of actual fuels burned.

The mineral analyses of the coals tested, given in Table 2-1, show that the western coal contains a high percentage of lime (CaO), and magnesia (MgO). The amount of sulfur trioxide retained in the ash closely approximates the lime content of the ash in all cases. This suggests that the CaO may tie up some of the sulfur as a sulfate. The western coal with its greater lime content retains more sulfur than the eastern coal as indicated by the data in Table 2-7.

Gronhovd, et al. (Ref. 2-2) have published a study of sulfur oxides emissions from lignite-fired power plants. They found significant amounts of sulfur retained by the ash. They could satisfactorily correlate their data by using the following relationship:

Sulfur emitted, as % of sulfur in coal =

$$110.1 - 12.7 \left(\frac{\%\ CaO}{\%\ Al_2O_3}\right) - 48.1 \left(\frac{\%\ Na_2O}{\%\ SiO_2}\right)$$

This correlation could not predict the amount of sulfur emitted in the flue gas as SO_2 when the subbituminous coals used in this study were compared to the actual emissions. The Gronhovd correlation gave consistently higher emission factors than actually measured.

Table 2-7 contains the results of fuel sulfur analyses and SO_2 emission analyses for six western and eastern coals. The fuel analysis and the SO_2 emissions analysis for the same tests were compared for each coal. The results were averaged where there was more than one test. The results show that on the average, the western subbituminous coal emitted only 80% of the available fuel sulfur, whereas the eastern base coal emitted 90.4% of the available fuel sulfur under comparable boiler operating conditions.

It can be concluded from this data that naturally reduced sulfur emissions are influenced by coal type and are of a magnitude such that the reductions should be considered when choosing a coal for reasons of SO_x compliance.

Nitric Oxide--

Nitric oxide emissions from stokers exhibited a similar dependence on excess O_2 in the flue gas as were observed with pulverized coal firing. At constant load, nitric oxide emissions increased with increasing excess O_2. Additionally, nitric oxide emissions increased slightly with increasing load.

However, the slope of the NO vs. O_2 curve is less for stoker-fired units than for the higher intensity combustion devices. Figure 2-5 shows an interesting NO vs. O_2 result for a water-cooled vibrograte stoker. The western coal (Wyoming Bighorn) has a slope of 12 (ppm NO/% O_2) compared to the eastern coal (Kentucky Vogue) which has a slope of 35 (ppm NO/% O_2). Figure 2-6 gives the NO vs. O_2 plot for the same two coals on an overfed traveling grate stoker without a water-cooled grate. On this unit, both coals exhibit the same NO vs. O_2 dependence. In fact, of the boilers tested, the water-cooled grate was the only unit having different NO vs. O_2 slopes for the two coals tested. It is speculative as to whether the additional cooling of the grate affects the conversion of atmospheric nitrogen to NO.

Stokers have overall lower NO emissions than pulverized coal units since the stokers operate in a "staged combustion" configuration. The stokers that have little or no suspension burning such as underfed and overfed stokers have a greater degree of staging than do the spreader stokers. In the stoker, the fuel devolatizes in the fuel bed under reducing conditions, then is mixed with the combustion air above the bed. Mixing is provided by overfire air jets or by front or rear arches in the furnace. Clinkering in the fuel bed establishes a limit to the degree of staging that can be achieved on stokers. Figure 2-7 shows these limits for a 12.6 kg/s (100,000 lb/hr) steam spreader stoker.

Carbon Monoxide and Unburned Hydrocarbons--

Carbon monoxide (CO) and unburned hydrocarbons (UHC) emissions from stokers as with all combustion systems, can be controlled by providing adequate excess air and proper mixing to insure complete combustion. High excess air conditions can cause CO and UHC emissions as can too low a level of excess air. Figure 2-8 gives the results of CO emission measurements on a 12.6 kg/s (100,000 lb/hr) steam spreader stoker as a function of excess air for both eastern and western coal. At high load, 11.3 kg/s (90,000 lb/hr) steam, CO emissions increase with decreasing excess air. However, at low and intermediate loads, a point is reached where increasing excess air results in rapidly increasing CO emissions. This behavior was observed

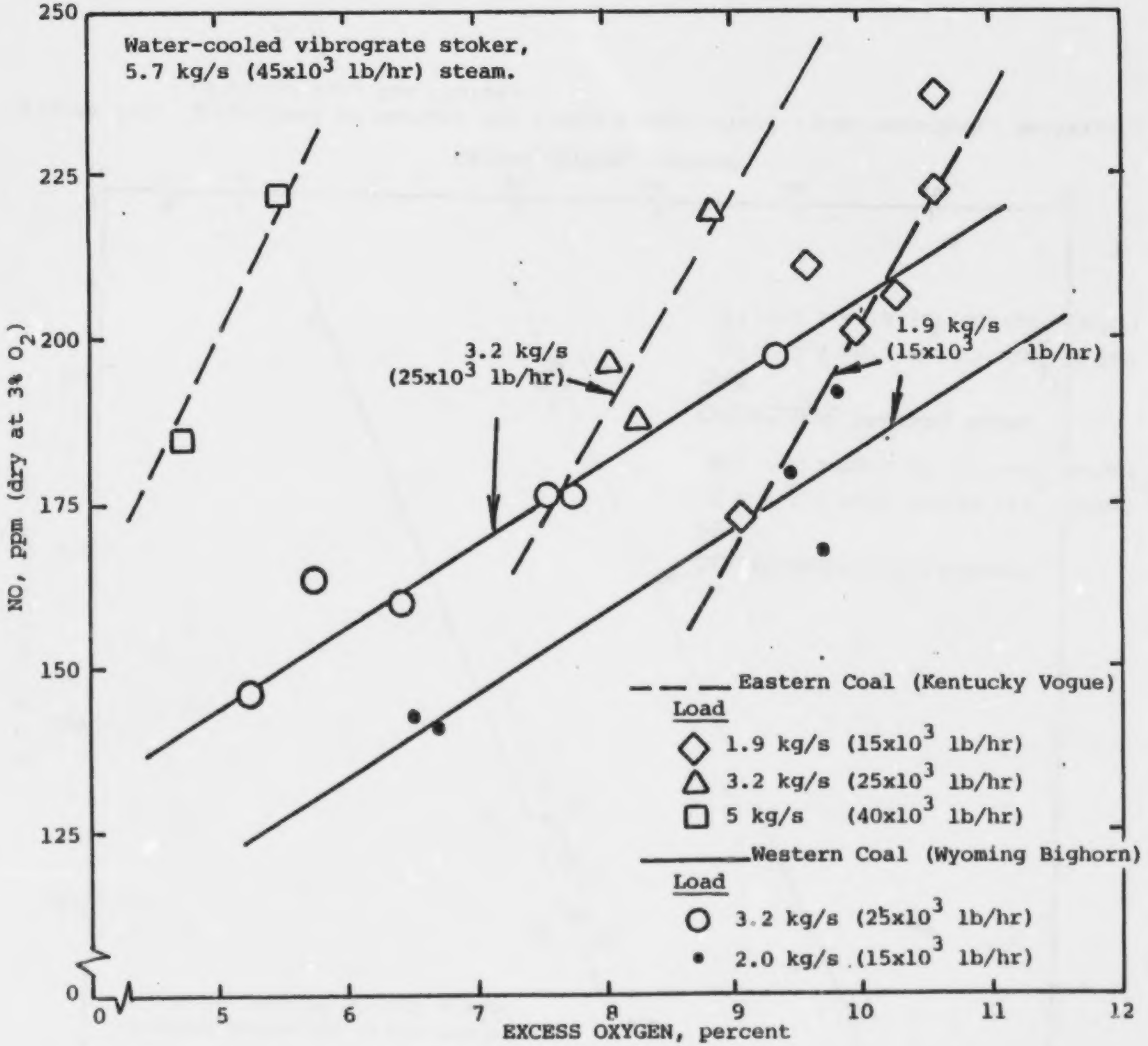


Figure 2-5. Comparison of western and eastern coal nitric oxide emissions, University of Wisconsin, Stout.

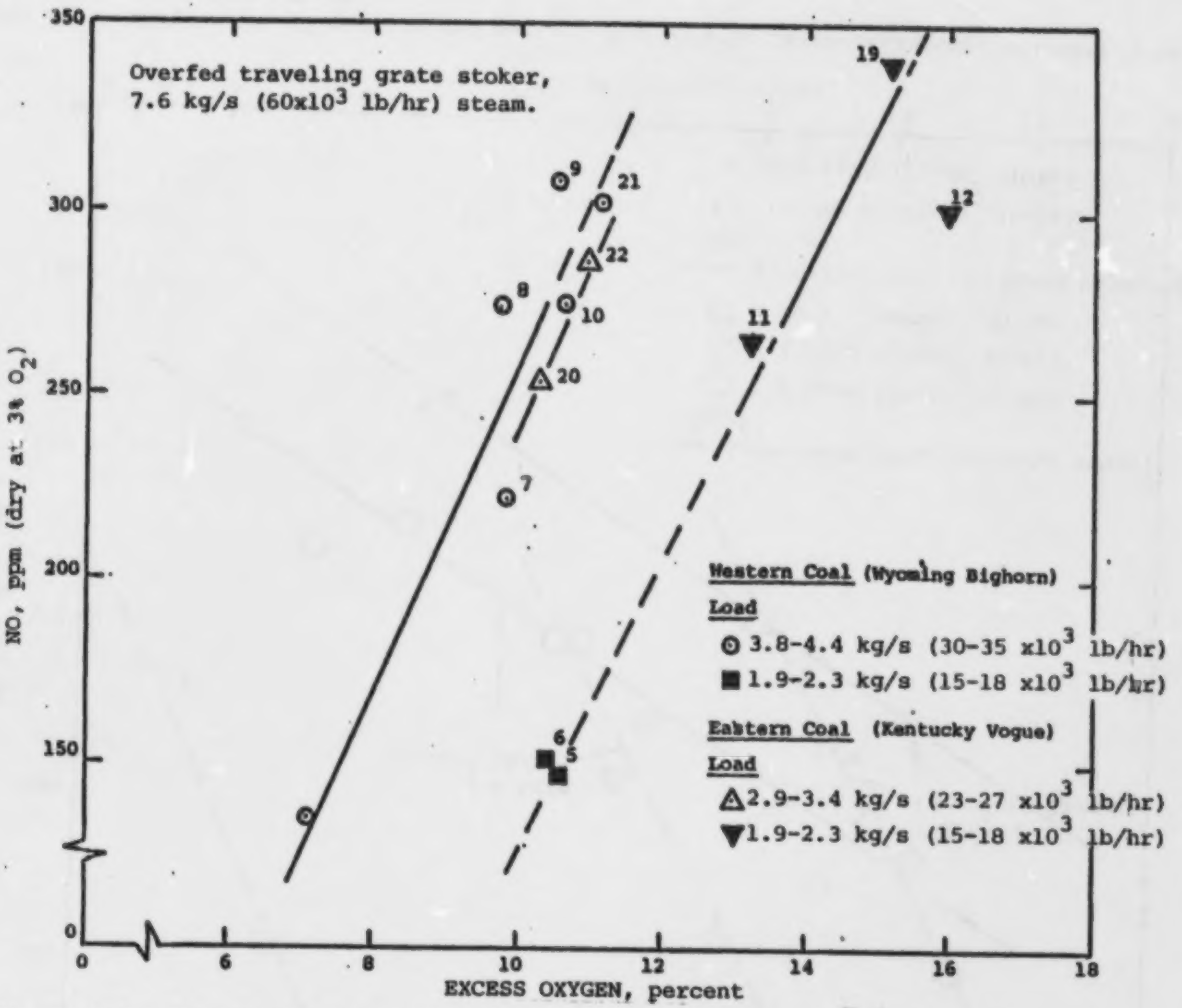


Figure 2-6. Comparison of western and eastern coal nitric oxide emissions, University of Wisconsin, Eau Claire.

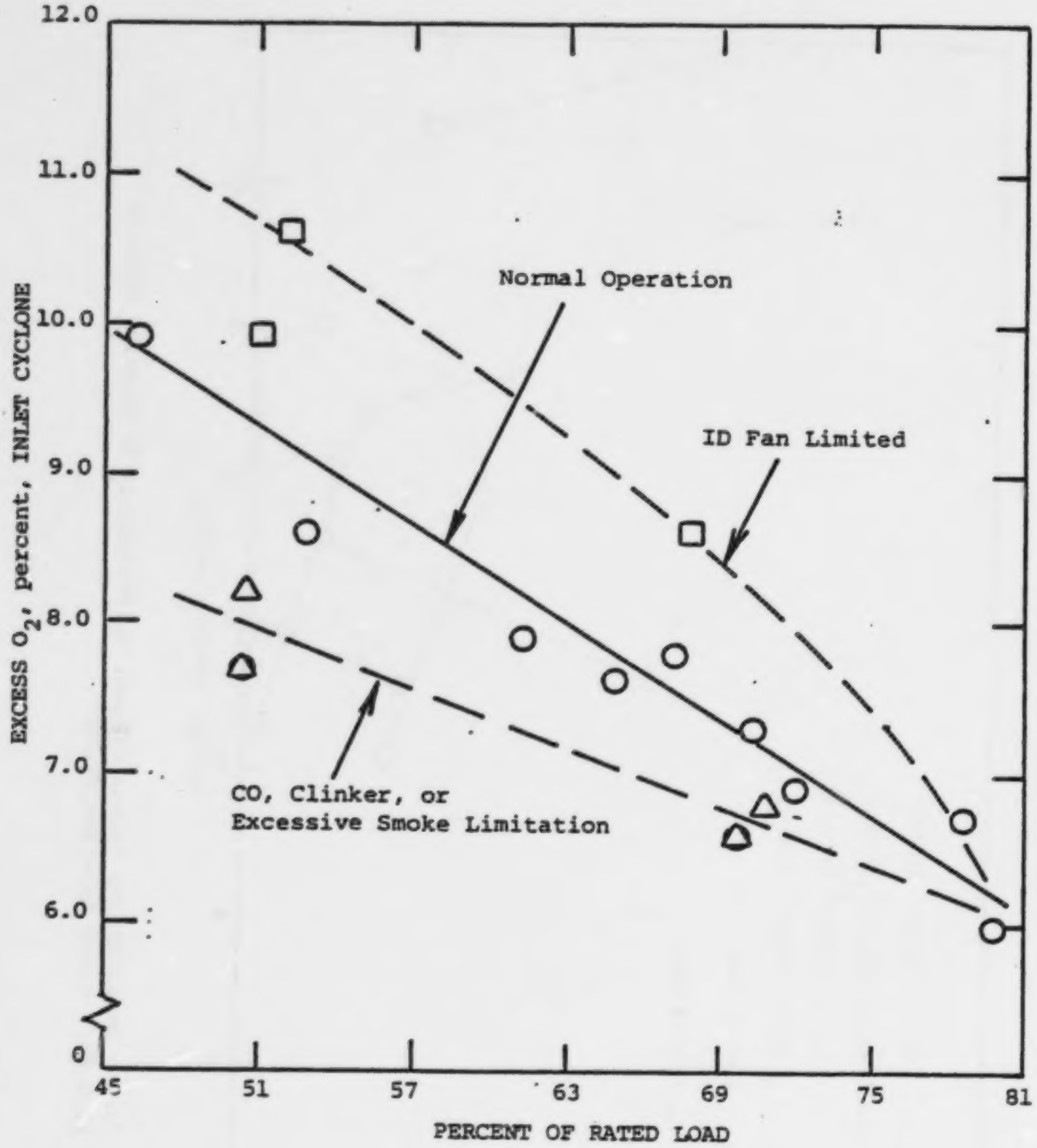


Figure 2-7. Stoker firing staging limits, Willmar Unit 3, 20.2 kg/s steam, western coal.

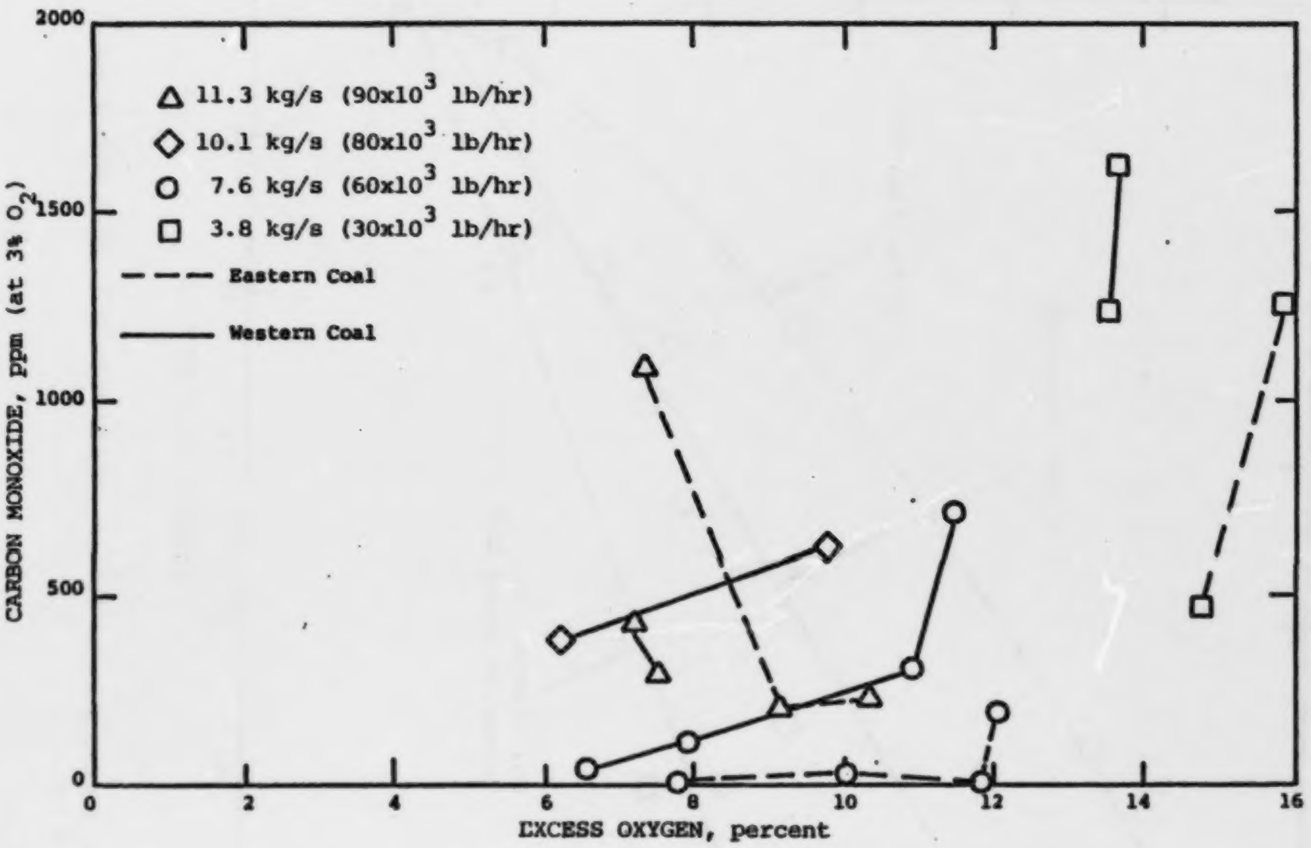


Figure 2-8. Carbon monoxide vs. excess oxygen, University of Wisconsin, Madison 12.6 kg/s steam spreader stoker.

for both coals. At low excess air, CO results from inadequate mixing of fuel and air. At high excess air settings, the fuel bed is thin even to the extent of some uncovered grate area which is thought to lead to local quenching of the flame by the combustion air and incomplete oxidation of CO to CO_2. The western coal can be fired at 2% lower excess O_2 at high load while producing comparable levels of CO emissions. This translates to higher unit efficiency because of lower dry gas and combustible losses.

Table 2-9 contains unburned hydrocarbon emission data for both an eastern and a western coal on the same spreader stoker unit described above. Unburned hydrocarbon emissions were higher at low load and high excess air than at high load and normal excess air, thus following the same trends as the CO emissions. No appreciable differences in UHC emissions were noted between eastern and western coals.

TABLE 2-9. COMPARISON OF HC EMISSIONS FROM EASTERN AND WESTERN COALS

Load		Eastern Coal		Western Coal	
kg/s	(10^3 lb/hr)	O_2(%)	HC (corr. ppm)	O_2(%)	HC (corr. ppm)
5.0	40	15.	114	13.8	125
7.6	60	12.7	54	11.3	18
11.3	90	9.7	48	--	--
11.3	90	8.7	44	8.8	44

Carbon monoxide emissions are a much more sensitive measure of incomplete combustion than are unburned hydrocarbons. A comparison of CO emissions and carbon carryover can be made. Figure 2-9 is a plot of percent carbon in the outlet flyash of a 20.2 kg/s (160,000 lb/hr) steam spreader stoker firing western (Montana) coal. This unit exhibited rather high carbon losses which increased with unit load. The carbon losses on eastern coal were even larger

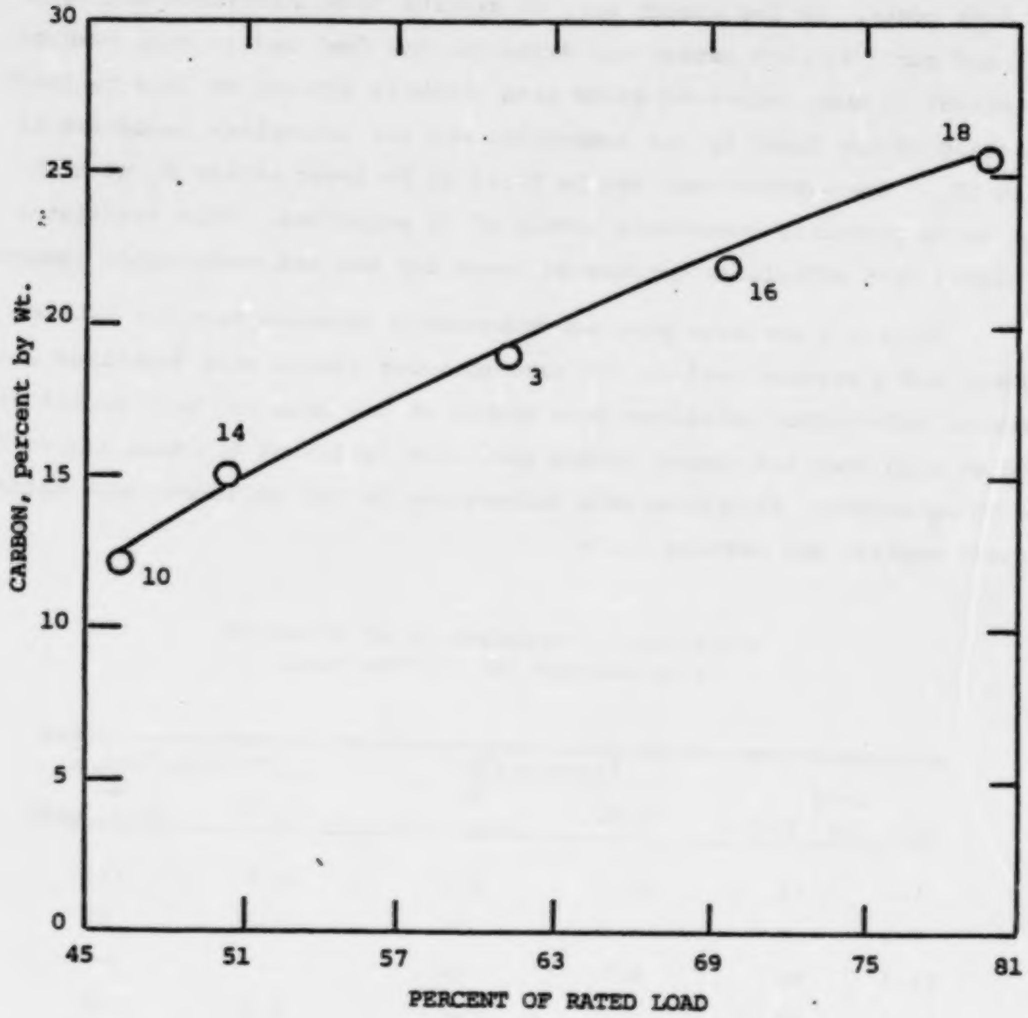


Figure 2-9. Percent carbon in outlet fly ash, Willmar Unit 3, 20.2 kg/s steam spreader stoker, western coal.

than for the western coal. However, the point to be made here is that by measuring the carbon monoxide emissions, an indication of the other combustible losses can be gained. The CO emissions for the same tests are shown in Figure 2-10.

Particulate Emissions--

Three types of stoker-fired boilers were tested. They were

- spreader stoker
- vibrating grate stoker
- traveling grate stoker

Within the spreader stoker category, four unit sizes and two grate configurations were tested. The stoker at St. Johns was fitted with a dumping grate while the boilers at Madison, Willmar, and Fairmont were all equipped with traveling grates. The spreader stokers with their greater degree of suspension burning and thin fuel bed have higher particulate emissions than the mass fed vibrating grate and traveling grate stokers. The spreaders are intermediate between the pulverized coal units and the mass fed stokers. Uncontrolled particulate emissions from spreader stokers average about 858 ng/J (2 lb/MBtu).

In three of the four spreader stokers, western coal produced markedly lower particulate emissions. In the case of Madison, both eastern and western coal produced the same particulate loadings although the western coal had 16% more ash. The combustible content of the western coal fly ash was half that of the eastern.

Dramatic reductions in particulate emissions were obtained on both a vibrating grate stoker (65%) and a traveling grate stoker (31%) by switching to western coal. These units both have inherently low particulate emissions because the combustion takes place in thick fuel beds with little or no suspension burning.

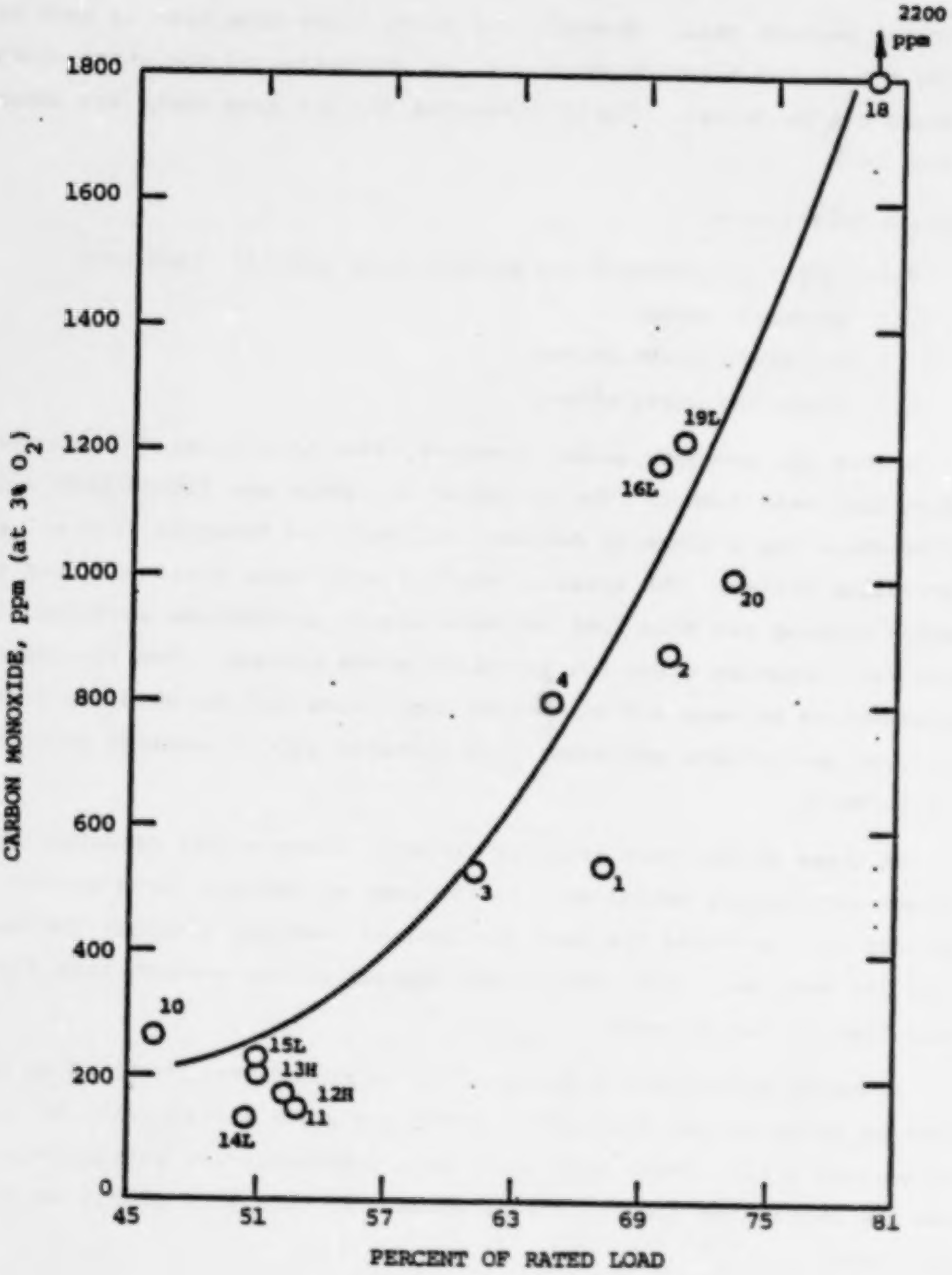


Figure 2-10. Carbon monoxide emissions vs. load, Willmar Unit 3, 20.2 kg/s steam spreader stoker, western coal.

For a given ash content in the coal, the quantity of particulate matter in the flue gas from stoker-fired boilers depends primarily upon the amount of burning that takes place in suspension or on the grate. Table 2-8 gives an average flue gas particulate loading from both eastern and western coals as measured before the control device for the stoker types tested as well as pulverized coal-fired boilers.

Spreader stokers with the greater suspension burning have from two to three times the particulate loading of the traveling grate and the vibrograte stokers. On the average, the western coal test results showed a 32% lower particulate loading than the eastern coal.

In summary it can be concluded that there is a distinct advantage from a particulate emissions standpoint, for switching to western coals.

2.3.3 Western Coal Efficiency Tests

Figure 2-11 presents boiler efficiency data as a function of boiler load at two different coal-fired boilers each burning an eastern bituminous low moisture coal and a western subbituminous high moisture coal. Data are shown for a 12.6 kg/s (100,000 lb/hr) spreader stoker with a traveling grate and a 4-burner wall-fired, 29 kg/s (230,000 lb/hr) pulverized coal unit. The latter boiler was equipped with a tubular air preheater while the stoker was equipped with a feedwater economizer.

An examination of the curves in Figure 2-11 suggests both boiler-to-boiler efficiency differences and the importance of coal properties on the efficiency characteristics of an individual boiler. The efficiency of the pulverized coal boiler is greater than the stoker efficiencies over the load range primarily due to the higher excess oxygen and combustible loss characteristics of the stoker boiler. Although dissimilar heat recovery devices are used at each boiler (air preheater versus economizer) this has little impact on the efficiency comparisons since stack temperatures were roughly equivalent at both boilers.

Firing with western coal reduced the efficiency of the pulverized coal boiler by approximately 5% while very similar efficiencies were exhibited by both coals on the stoker unit. In the first case the shift in efficiency

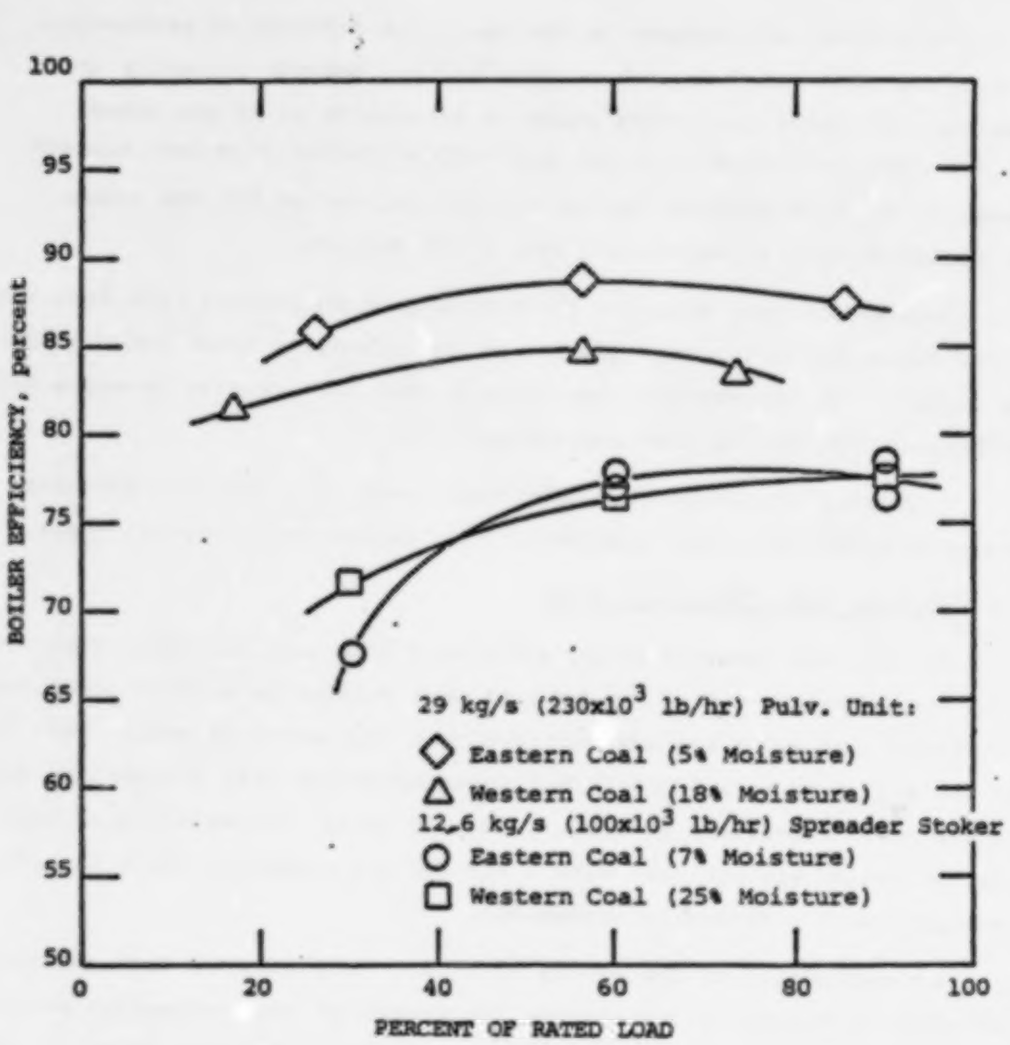


Figure 2-11. Boiler efficiency comparison of pulverized coal firing to spreader stoker coal firing for a high and low moisture coal type.

is attributed to the dissimilar moisture content of the two coals which resulted in different "moisture" heat losses. Slight variations in excess O_2 levels, stack temperatures, and combustibles had no appreciable effect on the other heat losses (dry gas, solid, and gaseous combustible losses).

For the stoker unit, a similar impact on efficiency would be expected if coal properties were the only variable. However, in this case, the combination of higher combustible losses experienced with the eastern coal resulted in similar efficiencies. As a point of interest, the combustible losses were less than 1% for all the pulverized coal tests shown, whereas combustible losses on the stoker unit were 2% to 4% and 7% to 11% for the western and eastern coals respectively. The absence of cinder reinjection and combustion air preheat on the stoker boiler contributed to the rather high combustible losses.

REFERENCES FOR SECTION 2.0

2-1. de Lorenzi, O. (ed.), Combustion Engineering, Combustion Engineering Company, Inc., p. 7-8, 1947.

2-2. Gronhovd, G. H., Tufte, P. H., and Selle, S. J., "Some Studies on Stack Emissions from Lignite-Fired Power Plants," Presented at 1973 Lignite Symposium, Grand Forks, ND, May 9-10, 1973.

SECTION 3.0

RECOMMENDATIONS FOR FURTHER WORK

The major areas of future work on western coals as defined by this program are as follows:

- Coal drying
- Coal sizing for stokers
- Demonstration of sulfur retention by the ash.

Drying western coals will increase the heat content of the coal and should improve the performance of these coals on units designed for higher Btu coals.

Facilities and techniques for local coal sizing should be developed to provide stoker quality coal to industrial users. Proper load preparation prior to shipment should reduce coal size deterioration in transit.

Further work should be done on the sulfur retention characteristics of most western coals. Some work has been done on this problem, the results are contained in Appendix F. This project showed the potential for substantial retention of fuel sulfur in the boiler ash. The mechanism of this retention should be investigated and demonstrated in order to optimize the conditions for maximum sulfur reductions.

SECTION 4.0

TEST EQUIPMENT AND PROCEDURES

This section details specific emissions measurements, and the sampling procedures followed, to assure accurate, reliable data collection.

4.1 GASEOUS EMISSIONS MEASUREMENTS

This section describes the analytical instrumentation and related equipment used to measure NO, NO_2, CO, CO_2, O_2, and hydrocarbons. The gas sampling and conditioning system are described. This equipment is located in a mobile testing van owned and operated by KVB. The systems described below were developed as a result of over five years of field testing.

4.1.1 Analytical Instruments and Related Equipment

The analytical system consists of five instruments and associated equipment for simultaneously measuring the composition of the flue gas. The analyzers, recorders, valves, controls, and manifolding are mounted to a panel in the van. The analyzers are shock-mounted to prevent damage from vibration. The flue gas constituents measured are oxides of nitrogen (NO, NO_x), carbon monoxide (CO), carbon dioxide (CO_2), oxygen (O_2), and gaseous hydrocarbons (HC). A detailed discussion of each analyzer follows.

The oxides of nitrogen monitoring instrument used is a Thermo Electron Model 10 chemiluminescent nitric oxide analyzer. The operational basis of the instrument is the chemiluminescent reaction of NO and O_3 to form NO_2. Light emission results when electronically excited NO_2 molecules revert to their ground state. The resulting chemiluminescence is monitored through an optical filter by a high sensitivity photomultiplier, the output of which is linearly proportional to the NO concentration.

Ambient air for the ozonator is drawn through an air dryer and a 10 micron filter element. Flow control for the instrument is accomplished by means of a small bellows pump mounted on the vent of the instrument, downstream of a separator, which insures that no water collects in the pump.

The basic analyzer is sensitive only to NO molecules. To measure NO_x (i.e., NO + NO_2), the NO_2 is first converted to NO. This is accomplished by a converter which is included with the analyzer. The conversion occurs as the gas passes through a thermally insulated, resistance heated, stainless steel coil. With the application of heat, NO_2 molecules in the sample gas are reduced to NO molecules, and the analyzer now reads NO_x. NO_2 is obtained by the difference in readings obtained with and without the converter in operation.

Specifications:

Accuracy: ± 1% of full scale

Span Stability: ± 1% of full scale in 24 hours

Zero Stability: ± 1 ppm in 24 hours

Power Requirements: 115 ± 10 V, 60 Hz, 1000 watts

Response: 90% of full scale in 1 sec (NO_x mode),
0.7 sec NO mode

Output: 4-20 ma

Sensitivity: 0.5 ppm

Linearity: ± 1% of full scale

Vacuum detector operation

Range: 2.5, 10, 25, 100, 250, 1000, 2500, 10,000 ppm
full scale

Carbon monoxide concentration is measured by a Beckman Model 315B nondispersive infrared (NDIR) analyzer. This instrument measures the differential in infrared energy absorbed from energy beams passing through a reference cell (containing a gas selected to have minimal absorption of infrared energy in the wavelength absorbed by the gas component of interest) and a sample cell through which the sample gas flows continuously. The differential absorption appears as a reading on a scale from 0 to 100 and is then related to the concentration of the specie of interest by calibration curves supplied with the instrument.

Specifications:

Accuracy: ± 1% of full scale
Span Stability: ± 1% of full scale in 24 hours
Zero Stability: ± 1% of full scale in 24 hours
Ambient Temperature Range: 32 °F to 120 °F
Line Voltage: 115 ± 15V rms
Response: 90% of full scale in 0.5 or 2.5 sec
Output: 4-20 ma
Range: 0-500 and 0-2000 ppm CO

Carbon dioxide concentration is measured by a Beckman Model 864 short path-length NDIR analyzer. This instrument measures the differential in infrared energy absorbed from energy beams passing through a reference cell (containing a gas selected to have minimal absorption of infrared energy in the wavelength absorbed by the gas component of interest) and a sample cell through which the sample gas flows continuously. The differential absorption appears as a reading on a scale from 0 to 100 and is then related to the concentration of the specie of interest by calibration curves supplied with the instrument.

Specifications:

Accuracy: ± 1% of full scale
Span Stability: ± 1% of full scale in 24 hours
Zero Stability: ± 1% of full scale in 24 hours
Ambient Temperature Range: 32 °F to 120 °F
Line Voltage: 115 ± 15V rms
Response: 90% of full scale in 0.5 or 2.5 sec
Output: 4-20 ma
Range: 0-5% and 0-20% O_2

A Teledyne Model 326A oxygen analyzer is used to automatically and continuously determine the oxygen content of the flue gas sample. Oxygen in the flue gas diffuses through a Teflon membrane and is reduced on the surface of the cathode. A corresponding oxidation occurs at the anode internally and an electric current is produced that is proportional to the concentration of oxygen. This current is measured and conditioned by the instrument's electronic circuitry to give a final output in percent O_2 by volume.

Specifications:

Accuracy: ± 1% of full scale
Response: 90% in less than 40 sec.
Sensitivity: 1% of low range
Linearity: ± 1% of full scale
Ambient Temperature Range: 32 °F to 125 °F
Fuel Cell Life Expectancy: 40,000 + hours
Power Requirement: 115 VAC, 50-60 Hz, 100 watts
Output: 4-20 ma
Range: 0-5%, 0-10%, 0-25% O_2 full scale

Hydrocarbons are measured using a Beckman Model 402 hydrocarbon analyzer which utilizes the flame ionization method of detection. The sample is drawn through a heated line to prevent the loss of higher molecular weight hydrocarbons to the analyzer. It is then filtered and supplied to the burner by means of a pump and flow control system. The sensor, which is at the burner, has its flame sustained by regulated flows of fuel (40% hydrogen + 60% helium) and air. In the flame, the hydrocarbon components of the sample undergo a complete ionization that produces electrons and positive ions. Polarized electrodes collect these ions, causing a small current to flow through an electronic measuring circuit. This ionization current is proportional to the concentration of carbon atoms which enter the burner.

Specifications:

Accuracy: ± 1% of full scale
Full scale sensitivity, adjustable from 5 ppm CH_4 to 10% CH_4
Response Time: 90% full scale in 0.5 sec

Electronic Stability: ± 1% of full scale for successive identical samples

Reproducibility: ± 1% of full scale for successive identical samples

Analysis Temperature: Ambient

Ambient Temperature: 32 °F to 110 °F

Output: 4-20 ma

Electrical Power Requirements: 120 V, 60 Hz

Automatic Flame-Out Indication and Fuel Shut-Off Valve

Range: 5 ppm full scale to 10% full scale as CH_4

Recording instruments. The outputs of the four analyzers are presented on front panel meters and are simultaneously recorded on strip chart recorders. The recorder specifications are as follows:

Specifications:

Strip Chart Display

Chart Size: 9-3/4 inch

Accuracy: ± 0.25%

Linearity: < 0.1%

Line Voltage: 120 V ± 10% at 60 Hz

Span Step Response: 1 sec

4.1.2 Gas Sampling and Conditioning System

The gas sampling and conditioning system consists of the probes, sample line, valves, pumps, filters, and other components necessary to deliver a representative, conditioned gas sample to the analytical instrumentation. The following section describes the system and the components which make up the system. The entire gas sampling and conditioning system shown schematically in Figure 4-1 is contained in the emission test vehicle.

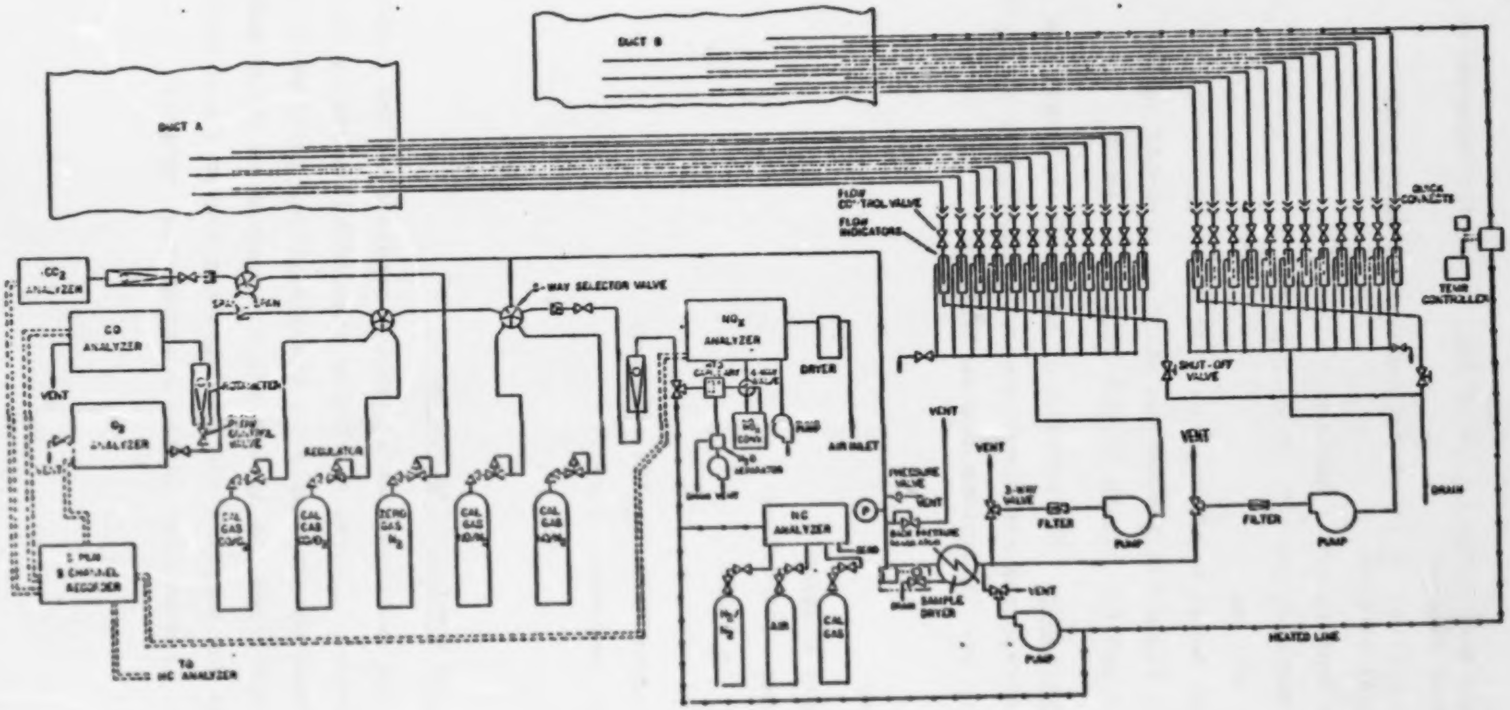

DUCT A
DUCT B
CO2 ANALYZER
CO ANALYZER
VENT
O2 ANALYZER
ROTAMETER
FLOW CONTROL VALVE
REGULATOR
3-WAY SELECTOR VALVE
CAL GAS
CAL GAS
ZERO GAS N2
CAL GAS
CAL GAS
8 CHANNEL RECORDER
TO HC ANALYZER
NOx ANALYZER
DRYER
PUMP
AIR INLET
AERATOR
HC ANALYZER
AIR
CAL GAS
P
PRESSURE VALVE
VENT
BACK PRESSURE
SAMPLE DRYER
VENT
3-WAY VALVE
FILTER
PUMP
VENT
FILTER
PUMP
VENT
PUMP
HEATED LINE
DRAIN
FLOW CONTROL VALVE
FLOW INDICATORS
SHUT-OFF VALVE
QUICK CONNECTS
TEMP CONTROLLER

Figure 4-1. Flow schematic of mobile flue gas monitoring laboratory.

4.2 GASEOUS EMISSION SAMPLING TECHNIQUES

Boiler access points for sampling were selected as near as possible to comply with the EPA guidelines regarding number and location. Probe bundles dividing the duct into equal area sampling zones were installed. Each probe consisted of 1/2" 316 stainless steel heavy wall tubing. A 0.7 micron Pall-Trinity sintered stainless steel filter was attached to each probe for removal of particulate material.

Gas samples to be analyzed for O_2, CO, CO_2, and NO were conveyed to the KVB mobile laboratory through 3/8" nylon sample lines. After passing through bubblers for flow control, the samples passed through a diaphragm pump and a refrigerated dryer to reduce the sample dew point temperature to 35 °F. After the dryer, the sample gas was split between the various continuous gas monitors for analysis. Flow through each continuous monitor was accurately controlled with rotameters. Excess flow was vented to the outside. Gas samples were drawn sequentially from all probes for each test. The average emission values were reported except where stratification of the gase gases was severe or could be related to problems in the fuel bed. In special cases such as this,the values from each individual probe were reported.

For obtaining NO_2 and HC data, a heated sample line was used to prevent condensation losses. This line bypasses the bubblers and feeds the hydrocarbon and nitric oxide monitors directly. A heated filter removed particulate matter and flows were controlled with rotameters. Both of these instruments have sample pumps located after the analyzer so that they will not interfere with the sample gas. Heated line samples were drawn through a single fixed probe.

4.3 SULFUR OXIDES MEASUREMENT AND PROCEDURE

Measurement of SO_2 AND SO_3 concentrations was done by wet chemical analysis using the "Shell-Emeryville" method. In this technique, the gas sample is drawn from the stack through a glass probe (Figure 4-2), containing a quartz wool filter to remove particulate matter, into a system of three sintered glass plate absorbers (Figure 4-3). The first two absorbers contain aqueous isopropyl alcohol and remove the sulfur trioxide, the third

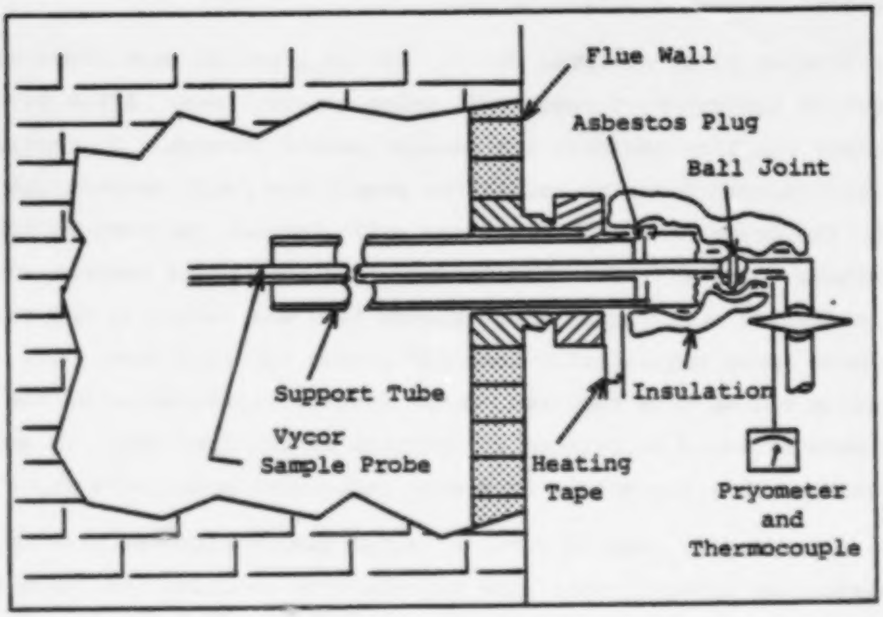

Flue Wall
Asbestos Plug
Ball Joint
Support Tube
Insulation
Vycor
Sample Probe
Heating
Tape
Pryometer
and
Thermocouple

Figure 4-2. Cutaway showing SO_2/SO_3 sampling probe.

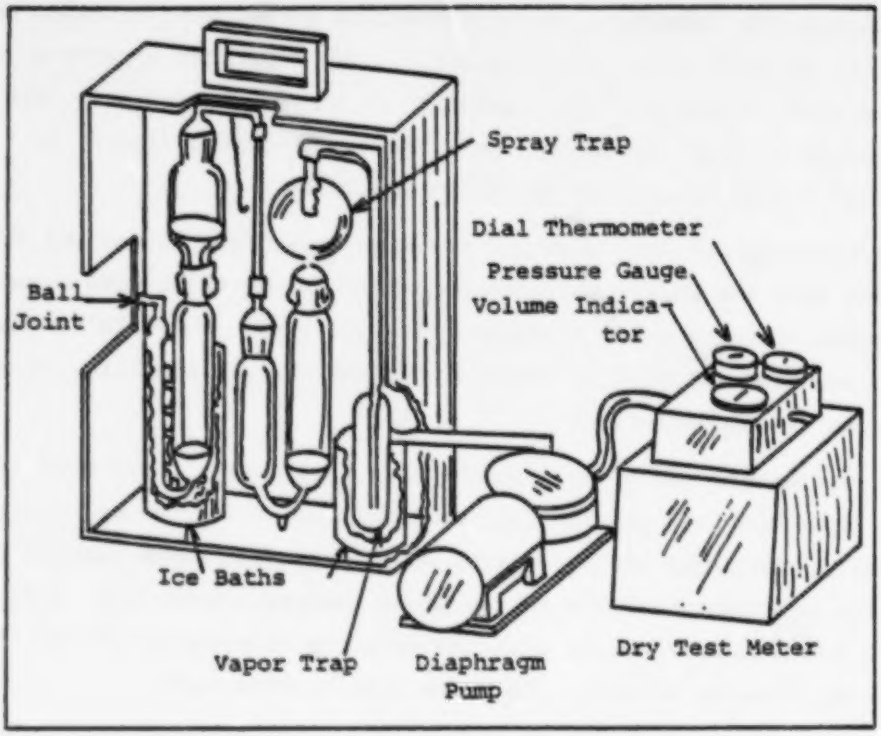

Spray Trap
Dial Thermometer
Pressure Gauge
Volume Indicator
Ball Joint
Ice Baths
Vapor Trap
Diaphragm Pump
Dry Test Meter

Figure 4-3. Shell-Emeryville SO_2/SO_3 sample system.

contains aqueous hydrogen peroxide solution which absorbes the sulfur dioxide. Some of the sulfur trioxide is removed by the first absorber while the remainder, which passes through a sulfuric acid mist, is completely removed by the secondary absorber mounted above the first. After the gas sample has passed through the absorbers, the gas train is purged with nitrogen to transfer sulfur dioxide, which has dissolved in the first two absorbers, to the third absorber to complete the separation of the two components. The isopropyl alcohol is used to inhibit the oxidation of sulfur dioxide to sulfur trioxide before it gets to the third absorber.

The isopropyl alcohol absorber solutions are combined and the sulfate resulting from the sulfur trioxide absorption is titrated with standard lead perchlorate solution using Sulfonazo III indicator. In a similar manner, the hydrogen peroxide solution is titrated for the sulfate resulting from the sulfur dioxide absorption.

The gas sample was drawn from the flue by a single probe made of quartz glass inserted into the duct approximately one-third to one-half way. The inlet end of the probe holds a quartz wool filter to remove particulate matter. It is important that the entire probe temperature be kept above the dew point of sulfuric acid during sampling (minimum temperature of 260 °C). This was accomplished by wrapping the probe with heating tape.

Three repetitions of SO_x were made at each test point.

4.4 PARTICULATES MEASUREMENT AND PROCEDURES

Particulate samples were taken at the same sample ports as the gaseous emission samples using a Joy Manufacturing Company portable effluent sampler (Figure 4-4). This system, which meets the EPA design specifications for Test Method 5, Determination of Particulate Emissions from Stationary Sources (Federal Register, Volume 36, No. 27, page 24888, December 23, 1971), was used to perform both the initial velocity traverse and the particulate sample collection. Dry particulates were collected in a heated case using first a cyclone to separate particles larger than 5 microns, and a 100 mm glass fiber filter for retention of particles down to 0.3 microns.

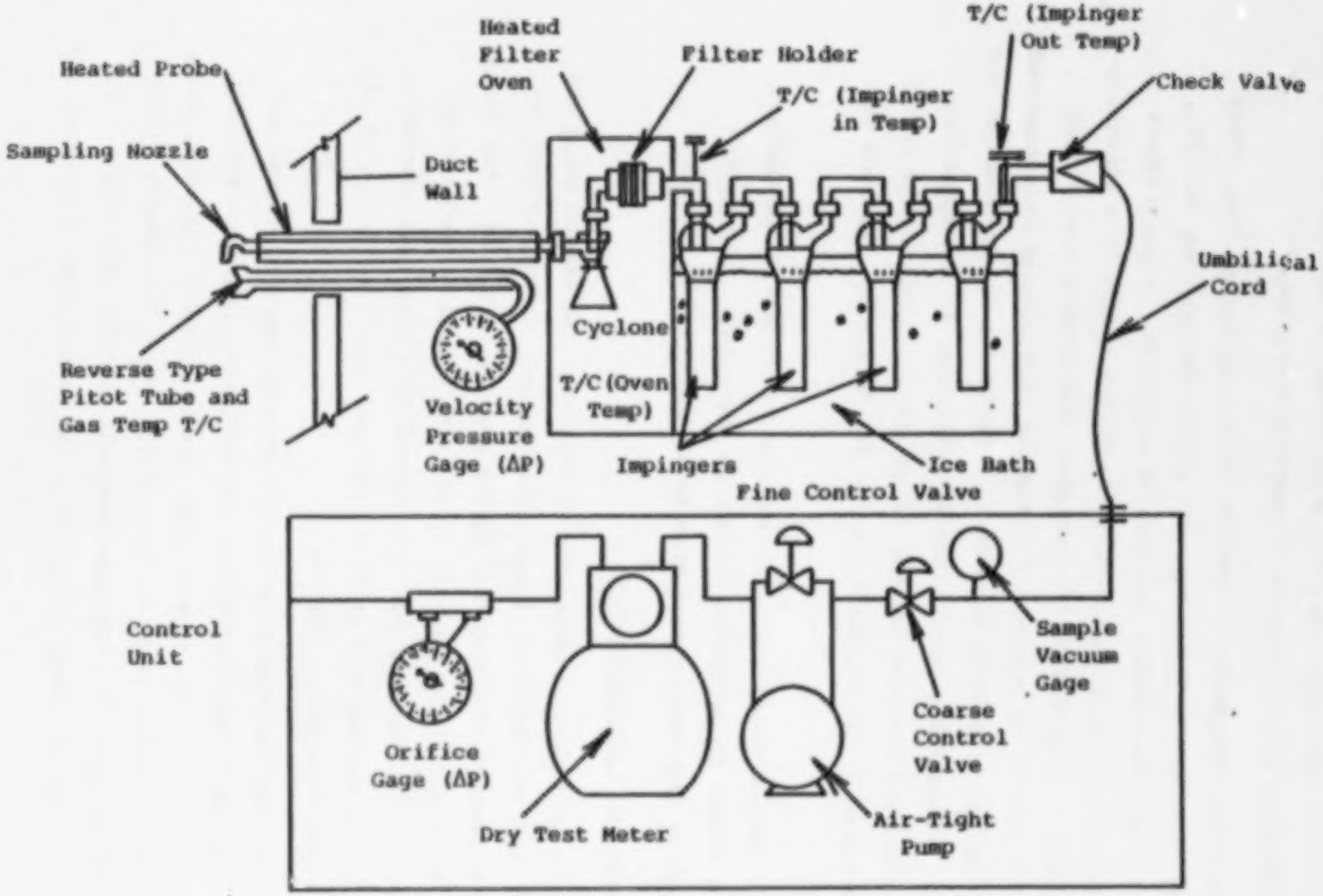

Heated Probe
Sampling Nozzle
Duct Wall
Reverse Type Pitot Tube and Gas Temp T/C
Velocity Pressure Gage (ΔP)
Heated Filter Oven
Filter Holder
Cyclone
T/C (Oven Temp)
T/C (Impinger in Temp)
T/C (Impinger Out Temp)
Check Valve
Umbilical Cord
Impingers
Ice Bath
Fine Control Valve
Control Unit
Orifice Gage (ΔP)
Dry Test Meter
Air-Tight Pump
Coarse Control Valve
Sample Vacuum Gage

Figure 4-4. Method 5 particulate sampling train.

Condensible particulates are collected in a train of four Greenburg-Smith impingers in an ice water bath. The control unit includes a total gas meter and thermocouple indicator. A pitot tube system is provided for setting sample flows to obtain isokinetic sampling conditions.

All peripheral equipment was carried in the instrument van. This included a scale (accurate to ± 0.1 mg), hot plate, drying oven (212 °F), high temperature oven, dessicator, and related glassware. A particulate analysis laboratory was set up in the vicinity of the boiler in a vibration-free area. Filters were prepared, tare weighed, and weighed again after particulate collection in this area. Condensible particulates were measured by boiling the impinger liquid to dryness in a container of known weight and then reweighing. Condensible particulate determination is not specified in EPA Method 5 but was included in many of the tests. Combustible particulates were measured by baking the filter at 750 °C for at least one hour and reweighing.

Testing was performed both upstream and downstream of the particulate collection device to determine collection efficiency. Multipoint (traverse) sampling was used in each case as in the EPA Test Method 5.

4.5 SAMPLING AND ANALYSIS PROCEDURE

Sampling and analysis proceeded as follows: the sample train was assembled with a filter baked to dryness for one hour at 783 °K (950 °F), dessicated, and weighed to a constant weight precise to 0.1 mg. The glassware, probe, and nozzles were washed, rinsed with distilled water three times, and dried. The impinger box and control unit were leak checked at 38.1 cm (15 in.) Hg vacuum to a leakage rate less than 566.4 cc (0.02 cfm). The probe was then attached to the box.

The probe was inserted into the gas stream, the pump turned on, and samples were taken isokinetically. The following data were recorded for each sample point: % O_2, sample time, static pressure (in. Hg), stack temperature (°F), velocity head, orifice ΔP (in. H_2O), gas sample volume (ft^3), oven temperature (°F), impinger temperature-inlet and outlet (°F), and dry gas meter outlet temperature (°F). The sample pump was turned off while the sample train was moved from one location to the next. At the conclusion of the test, the probe was removed from the gas stream, the sample pump was turned off, and a final set of data were taken.

The equipment was then taken to the laboratory where the probe was washed twice with reagent grade acetone, then cleaned with a probe brush, and washed again with acetone. The acetone washings and probe brush rinse were collected in clean dry sample bottles. The cyclone, sampling nozzle, and collection flask were emptied into a tared 250 ml beaker and washed in the same manner as the probe with the washings collected in the same sample bottle. The collection filter was removed from the filter holder and transferred to a petri dish. The top bell jar of the filter holder and the connecting glassware were washed into the same sample bottle used for the probe washings. The volume of liquid collected in the impingers was measured and recorded. The first three impingers and connecting glassware with the bottom bell jar of the filter holder were rinsed with distilled water into a sample bottle which also contained the flue gas condensate collected by the impingers. The acetone rinses and the cyclone collection were dried and dessicated in tared 250 ml beakers, the filter was dried and dessicated. The beakers and filter were then weighed to a constant weight and the total amount of particulate collected was determined by addition of the individual component weights. A blank filter tare weight change was used to correct the sample filter weight difference for changes due to handling, baking, and humidity. Blank (control) samples of both the acetone and distilled water used in testing were also dried, dessicated, and weighed. Weight corrections for dissolved solids in the washing liquids were made as appropriate.

4.6 EFFICIENCY EVALUATION

Thermal efficiency is an important tradeoff consideration during the course of testing. A low emission operating mode may appear satisfactory on the surface but an increase in stack temperature , slagging or changes in steam temperatures may cause this mode to be discarded.

Boiler efficiency was calculated and reported using the ASME Test Form for Abbreviated Efficiency, revised September 1965, where possible. The general approach to efficiency evaluation was based on the assessment of combustion losses. The losses considered were stack gas composition/temperature and carbon carryover losses.

Flue gas composition parameters included CO_2 and O_2 as well as incomplete combustion parameters such as CO. Measurement of the combustible components of particulate matter were made. This was done by baking particulate collection filters at 750 °C for at least one hour.

Carbon carryover analysis was done by collecting ash samples at the various outlet points and baking a known quantity of ash at 750 °C for at least one hour.

These results, when coupled with a fuel analysis and ambient and exit temperatures, permitted a carbon/heat balance to be run. Steam parameters were recorded to assess changes.

SECTION 5.0

TEST RESULTS

5.1 DAIRYLAND POWER COOPERATIVE, ALMA, WISCONSIN

Unit #3, Dairyland Power Cooperative, Alma Station, was the first unit tested under this program. A total of 78 tests were run, the first 55 tests were on eastern coal and the last 23 on western coal. The unit tested was the largest pulverized coal burning boiler tested. The unit generated electricity for a rural populace in southern Wisconsin. The results were very encouraging for western coal use.

A special series of tests were conducted in which the sulfur retention properties of the western coal ash were investigated.

5.1.1 Boiler Description

The boiler tested was Unit #3 of the Dairyland Power Cooperative located in Alma, Wisconsin. This unit is a small, dry bottom, pulverized coal burning boiler built in 1950 by Riley Stoker Company. It is face fired with four Riley flare type burners which give it a rated capacity of 29 kg/s (230,000 lb/hr) steam flow. The burners are supplied with pulverized coal from two ball tube mill pulverizers. One mill feeds the top two burners while the other feeds the bottom two burners.

The unit was recently fitted with a cold side UOP electrostatic precipitator and a tall stack 183 m (600 ft). This stack height was required because of the facility's location in a river valley and the need to disperse the flue gases above the level of the river bluffs.

The furnace has balanced draft with the induced draft fan located after the electrostatic precipitator. The air heater is tubular, and the pendant type superheater has spray steam attemperation.

Additional boiler specifications are as follows:

- Design Pressure - 7.00 MPa (1,000 psig)
- Design Temperature - 755 °K (900 °F)
- Design Efficiency - 86.0% at 29 kg/s (230,000 lb/hr)
- Actual Day-to-Day Operating Conditions
  - Throttle pressure - 6.03 MPa (860 psig)
  - Drum pressure - 6.31 MPa (900 psig)
  - Superheat outlet temperature - 733 °K (860 °F)
- Furnace Width - 5.01 m (16'5-1/4")
- Furnace Depth - 2.53 m (21'1-1/8")
- Furnace Volume - 425 m^3 (15,000 ft^3)
- Boiler Heating Surface - 1189 m^2 (12,700 ft^2)
- Water Wall Heating Surface - 971 m^2 (10,450 ft^2)
- Heat Release - 20.36 MJ at 29 kg/s steam (19,300 Btu at 230,000 lb/hr)

Coal is unloaded from a river barge at this site. West Kentucky River King coal was the base coal tested. The western test coal came from Sarpy Creek, Montana. Testing was done during the summer months and, therefore, coal handling problems due to freezing of the coal were not observed. Fugitive dust during coal handling was not a problem.

Figure 5.1-1 shows the vertical layout of Alma Unit #3 as it looked prior to installation of the electrostatic precipitator. Table 5.1-1 summarizes the coal analysis made during the test period.

5.1.2 Sampling Locations

Gaseous and particulate emissions were measured upstream and downstream of the electrostatic precipitator (ESP). The geometry of the sample areas is shown in Figure 5.1-2.

The sample area upstream of the electrostatic precipitator was located just downstream of the old cyclone breeching. The cyclones, shown in Figure 5.1-1, were removed when the electrostatic precipitator was installed. The sample area consisted of 4 4-inch pipe ports. A bundle of 3 stainless steel

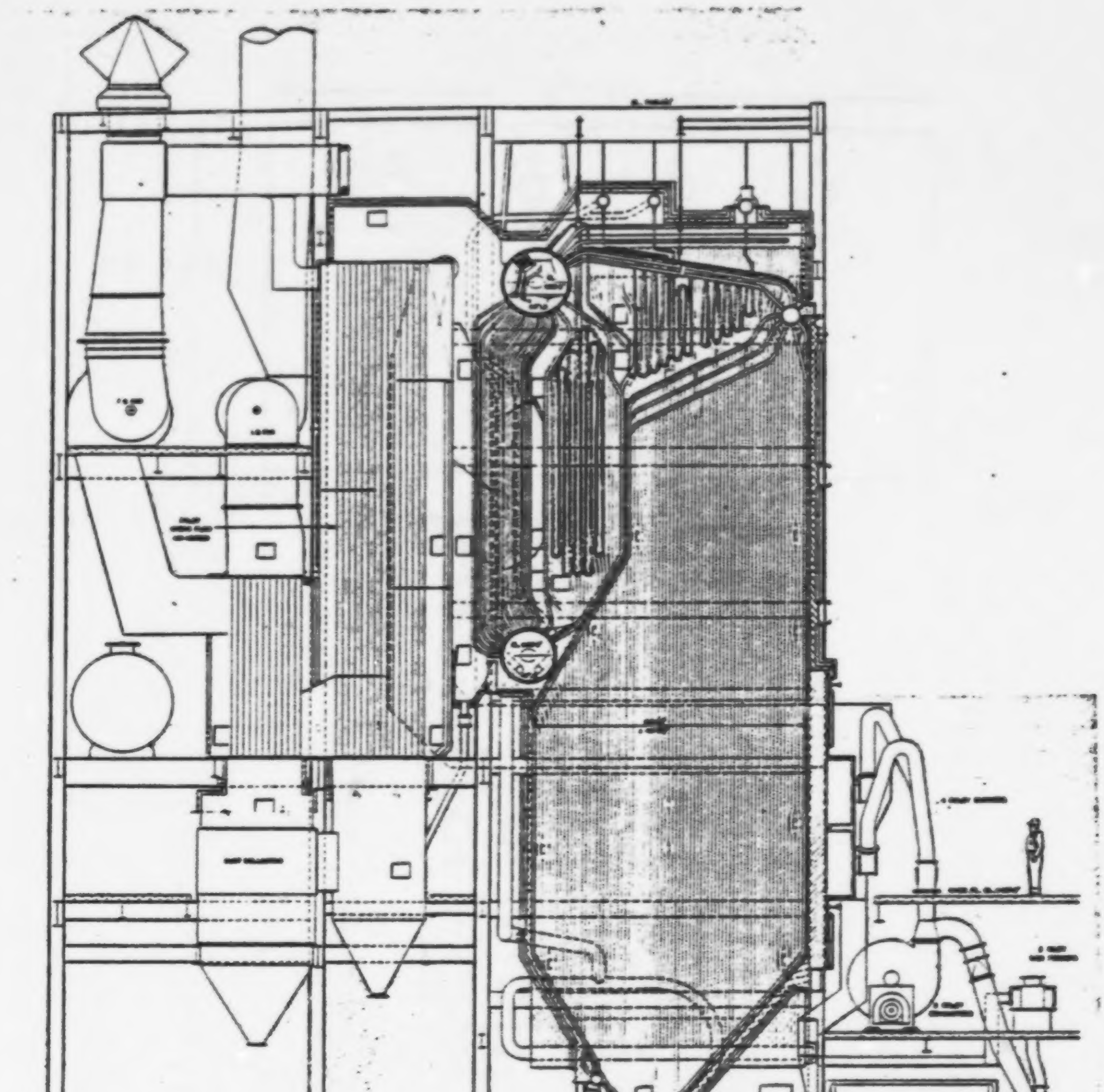
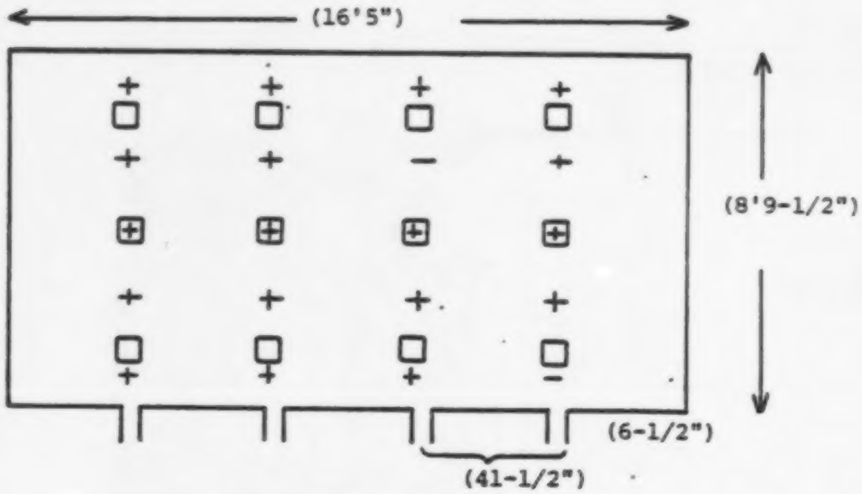
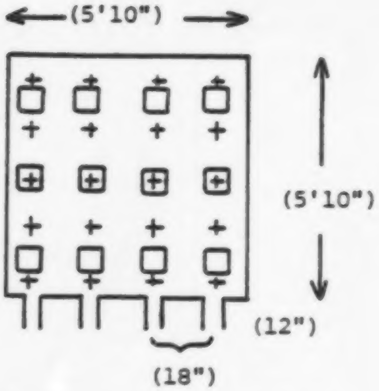


Figure 5.1-1. Vertical layout of Dairyland Power Cooperative's Unit 3, Alma, Wisconsin, before installation of the electrostatic precipitator.


(16'5")
(8'9-1/2")
(6-1/2")
(41-1/2")

Sample Area Upstream of ESP
Average temp.: 480 °K (405 °F)


(5'10")
(5'10")
(12")
(18")

Sample Area Downstream of ESP
Average temp.: 422 °K (300 °F)

+ Particulate sample point
□ Gaseous sample point

Figure 5.1-2. Sample area geometry, Dairyland Power Cooperative Unit 3.

TABLE 5.1-1. COAL ANALYSIS SUMMARY, UNIT #3, DAIRYLAND POWER COOPERATIVE ALMA, WISCONSIN

Test No.	Coal Type	As Received Proximate Analysis, %				As Recd Sulfur %	As Recd Htg Value MJ/kg (Btu/lb)
		Moisture	Ash	Volatile	Fixed Carbon		
6	W. Kentucky	1.68	16.00	60.00	22.32	3.65	—
9	W. Kentucky	5.15	15.96	61.65	17.24	4.23	—
16	W. Kentucky	2.20	19.02	61.20	17.58	3.26	—
55*	W. Kentucky	12.08	16.39	55.08	16.45	3.80	—
Average	W. Kentucky	3.01	16.99	60.95	19.05	3.71	25.043 (10,776†)
57	Montana	16.24	12.62	47.00	24.14	1.46	21.764 (9,365)
63	Montana	12.75	16.31	48.42	22.52	1.90	22.740 (9,785)
64*	Montana	20.09	18.19	48.89	12.83	0.79	—
72	Montana	17.23	12.64	37.30	32.83	1.36	22.520 (9,690)
73	Montana	17.94	10.67	36.30	35.09	0.86	21.846 (9,400)
74	Montana	17.94	11.56	36.80	33.71	0.84	—
75	Montana	19.33	11.19	37.70	31.78	0.84	21.613 (9,300)
76	Montana	18.89	11.36	38.30	31.55	0.79	21.962 (9,450)
78	Montana	17.75	12.32	38.06	31.87	0.78	21.570 (9,290)
Average	Montana	17.26	12.33	39.99	30.44	1.23	22.006 (9,469)

Coal Type	As Received Ultimate Analysis, %							As Recd Htg Value MJ/kg (Btu/lb)
	Moisture	Carbon	Hydrogen	Nitrogen	Sulfur	Ash	Oxygen by diff.	
W. Kentucky	7.46	59.87	4.24	1.09	3.68	14.49	9.17	25.043 (10,776†)
Montana #	17.26	55.44	4.03	0.73	0.81	10.04	11.69	21.697 (9,336)

* Samples taken from coal feeder, not included in averages because of higher moisture. Other samples from coal pipes leading to burners.

† Heating value calculated from Ultimate analysis, by Dulong's Formula.

# Mine analysis originally 25.11% moisture corrected to average "as-received" moisture.

probes were inserted into each port so that gaseous samples could be drawn from the centroid of twelve equal areas dividing the duct. Particulates were samples from the sample ports with a twenty-point traverse. Sulfur oxides were sampled from a single point using a 6-foot vycor probe. Initially, dropout flasks were used on each sample line to remove particulate matter. Later these were removed in favor of sintered stainless steel filters placed on the sampling end of the probes.

The sample locations downstream of the electrostatic precipitator was located after the induced draft fan. Access was provided by 4 4-inch pipe ports. Twelve stainless steel probes were installed but because stratification of the gases within the duct was almost nonexistent, only the center probe in each port was used. Sintered stainless steel filters were not required here due to the low particulate loadings. Particulates were sampled with a twenty-point traverse. Sulfur oxides were sampled from a single point using a 3-foot vycor probe.

5.1.3 Unit Operation

Alma Unit #3 performed well on both test coals with the exception that 13% of maximum load capacity was lost while burning Montana coal. This was due to excessive superheat steam temperatures. The steam attemperation system was not adequate to maintain steam temperatures below 744 °K (880 °F) at loads above 21.9 kg/s (174,000 lb/hr) steam flow on Montana coal. Although the unit was design rated at 29 kg/s (230,000 lb/hr), it has since been derated to 25.2 kg/s (200,000 lb/hr) and this was the maximum achievable load on eastern coal.

The primary factor causing the excessive steam temperature was the high moisture content of the Montana coal. Moisture reduces the flame temperature which in turn reduces the radiant heat flux (a function of temperature to the fourth power) to the water walls resulting in lower steam generation. Although less heat is removed in the radiant section of the boiler, the gas still contains a large enthalpy which acts on a decreased amount of steam in the convective section resulting in increased steam temperatures. Moisture in the fuel also results in greater gas flows which increase heat transfer rates in the convective pass.

Unit performance factors such as slagging and flame stability were not problems while burning Montana coal. Fouling in the superheat pendants was a problem. Increased tube spacing would help. Mill performance decreased somewhat but was not detrimental to unit performance as will be described below.

Pulverizing Mill Performance--

Eastern coking coals, when exposed to furnace temperatures, will swell and form lightweight, porous coke particles. These may float out of the furnace before they are completely burned. As a result, carbon loss will be high unless pulverization is very fine. Free burning (western) coals, on the other hand, do not require the same degree of fineness because the swelling characteristic is absent.

High-volatile (western) coals ignite more readily than those with a low volatile content. Therefore, they do not require the same degree of fine pulverization. With the exception of anthracite, however, the low-volatile coals are softer, and may be said to have a higher grindability. As a result, mill capacity is greater at increased fineness than with high-volatile coals (Ref. 1).

Table 5.1-2 shows the screen analysis, moisture content, and loads for the coal burned during several tests. Test number 16 was with one mill in operation and is thus equivalent to approximately twice the load when compared with the others.

TABLE 5.1-2. SCREEN ANALYSES OF PULVERIZED COAL

	EASTERN		WESTERN				
Test No.	9	16	57	63	73	75	78
Load, % Capacity	57	26	74	57	41	70	48
10^3 lb/hr	130	60	170	131	94	160	110
- 80 mesh, %	0.65	1.00	2.90	1.40	0.65	8.74	1.53
- 80 +100 mesh, %	0.75	1.00	2.30	1.30	2.32	7.70	2.23
-100 +140 mesh, %	2.75	3.35	20.65	4.05	8.91	21.65	6.60
-140 +200 mesh, %	6.95	8.20	34.60	8.30	32.26	16.75	17.46
-200 mesh, %	88.90	86.45	39.55	84.95	55.66	45.15	72.18
Moisture, %	5.15	2.20	22.05	12.75	17.94	19.33	17.75

It is seen that the western coal did not grind quite as well as the eastern coal. However, this is not thought to be a severe problem. As stated earlier, western coals do not require the same degree of fineness as eastern coals because of their higher volatile content and their free burning characteristics. It is noted that the grindability tends to follow the moisture content.

Boiler Optimization for Nitric Oxide--

A series of tests were conducted to determine the effect of air register setting, coal diffuser position, excess oxygen, and off-stoichiometric firing on the formation of nitric oxide. Limiting factors were the formation of carbon monoxide, flame impingement on the furnace walls and slagging tendencies of the different firing modes.

Air Registers were varied at peak load on eastern coal. They were opened towards the radial position until the flames began to impinge on the back wall, then they were closed down a little.

The overall trend seen for changing the air registers from tangential type flow to radial type flow was a decrease in NO emissions. NO was seen to decrease 17.5% from test #25 to test #27 as the air registers were made more radial in flow characteristics. The results are summarized in Table 5.1-3 below.

TABLE 5.1-3. EFFECT OF VARYING AIR REGISTERS
(Eastern Coal)

Test No.	Air Register Position	Excess O_2, %	CO Dry, ppm	NO Dry, ppm	Furnace Conditions
25	As Found	3.8	23	617	Good
26	Opened Toward Radial Position	3.5	26	546	Good
27	All in Radial Flow Position*	3.5	20	509	Slight Increase in Slagging at Burner Throat & Back Wall

(*Except lower left air register which was stuck)

Some slight increase in slagging was noted for the air registers in radial position. This slagging occurred around the burner throat and along the back wall. It was not considered serious.

Coal diffusers were varied while the air registers were in the tangential or as-found position. These tests were conducted at peak loading on eastern coal. From the various positions tried, it was concluded that varying the diffuser position did not change emissions characteristics significantly. There is some evidence here that nitric oxide emissions drop as the diffuser is pulled out. However, variations in excess oxygen mask this effect.

TABLE 5.1-4. EFFECT OF VARYING DIFFUSER POSITION
(Eastern Coal)

Test No.	Diffuser Position	Excess O_2, %	CO Dry, ppm	NO Dry, ppm
42	As Found	2.9	7	579
43	2" Out	3.2	14	594
44	1" In	2.9	15	611
45	As Found	3.4	16	687
46	As Found Air Reg. Radial	3.5	17	584

When the air registers were opened to the radial position for test #46, a 15% reduction in nitric oxide was observed. This reinforces the earlier findings concerning air register position. Thus, the optimized mode of operation for this unit is diffusers as-found and air registers in a maximum radial flow position without flame impingement on the back walls. This then became the normal operating mode for the western coal tests.

Excess oxygen has a pronounced effect on nitric oxide emissions in Alma Unit #3. This oxygen dependence is seen in Figures 5.1-3 and 5.1-4 where NO emissions are plotted against excess O_2 for both coals. To measure its effect in the optimized burner mode, the test series in Table 5.1-5 were run.

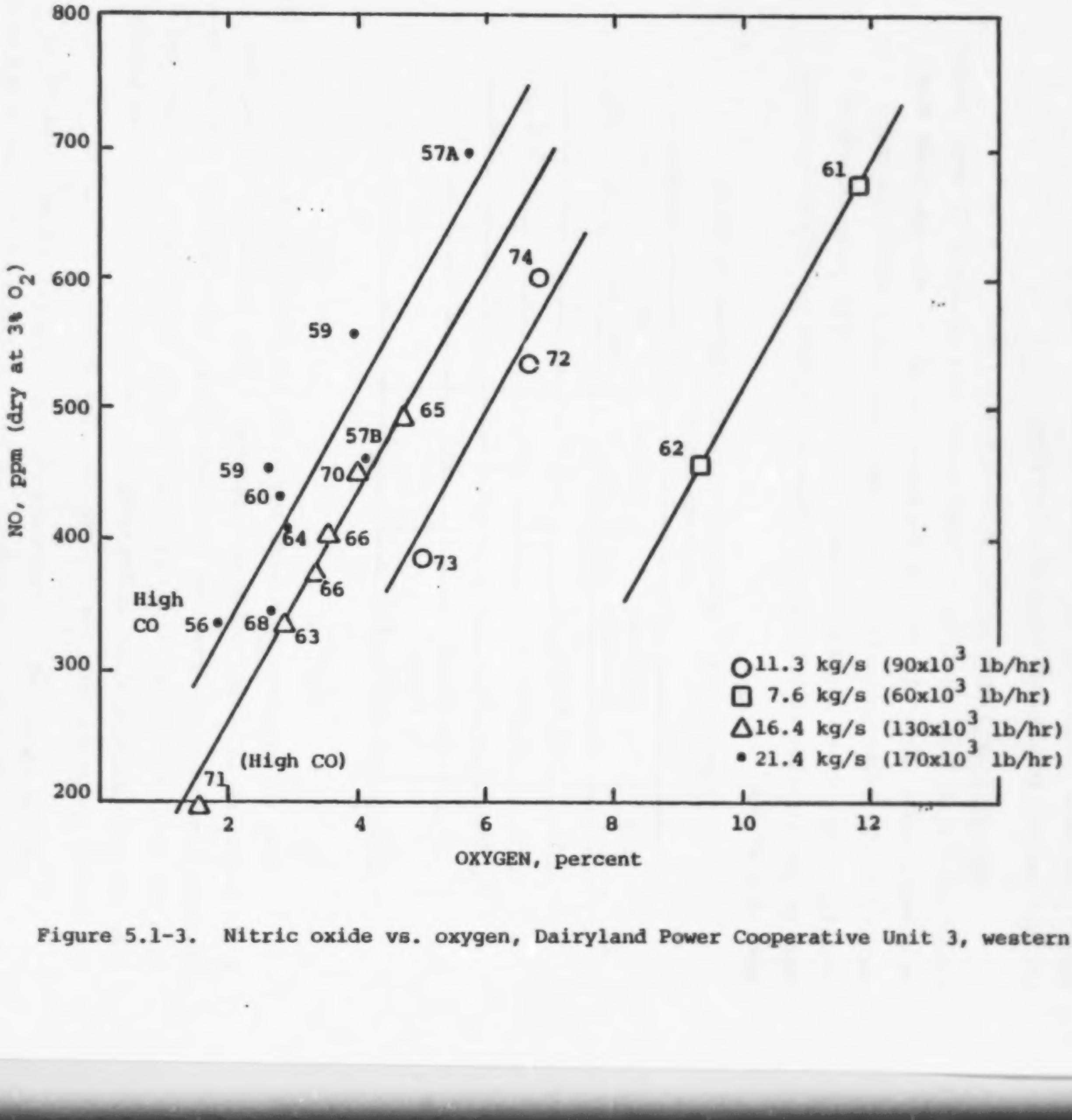


Figure 5.1-3. Nitric oxide vs. oxygen, Dairyland Power Cooperative Unit 3, western coal.

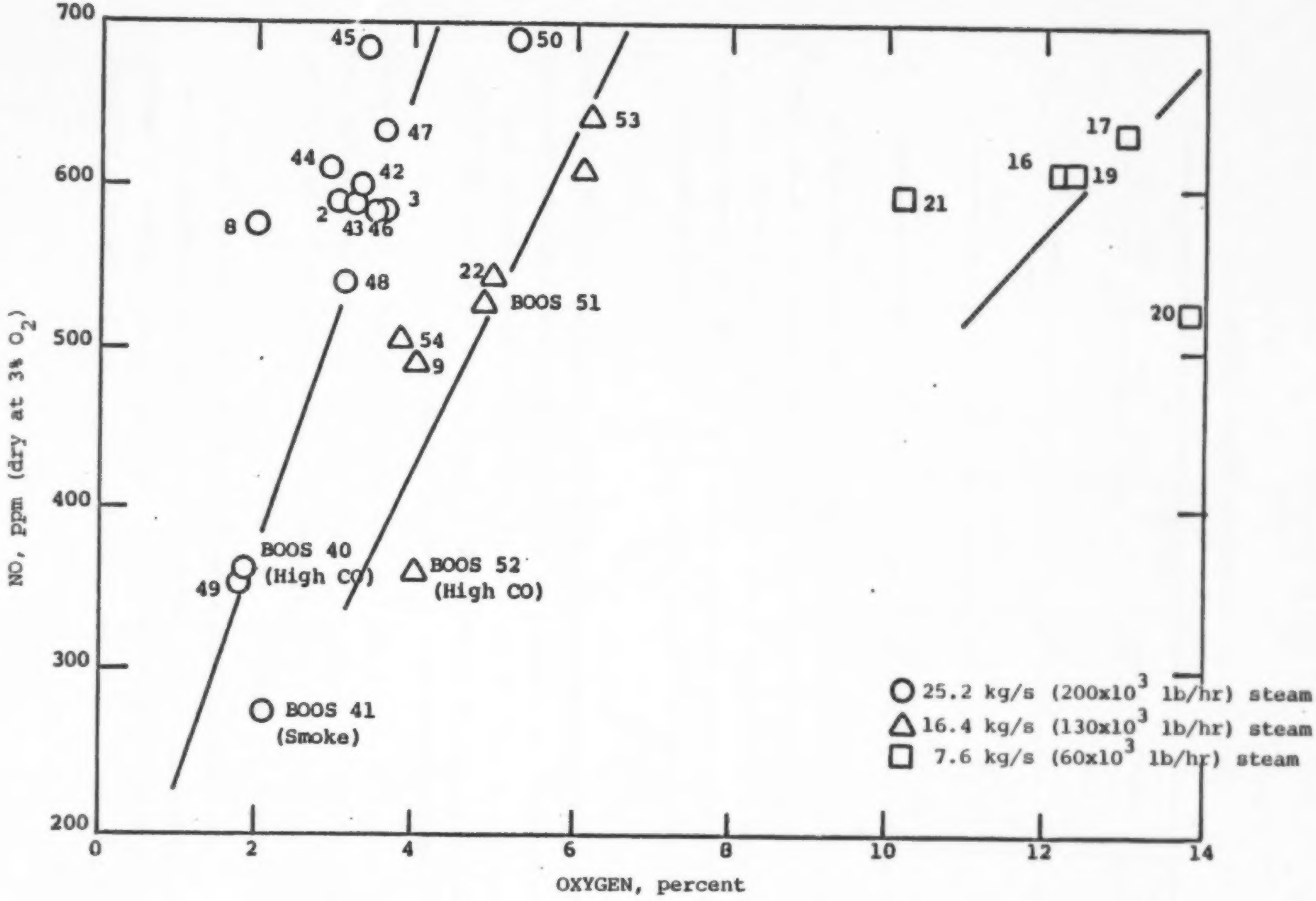


Figure 5.1-4. Nitric oxide vs. oxygen, Dairyland Power Cooperative Unit 3, eastern coal.

TABLE 5.1-5. EFFECT OF EXCESS OXYGEN
(Eastern Coal)

Test No.	Test Conditions	Excess O_2, %	CO Dry, ppm	NO Dry, ppm
47	Air Reg. As-Found Normal O_2	3.7	20	635
49	Air Reg. Radial Low O_2	1.8	570	355
50	Air Reg. Radial High O_2	5.2	20	690

It is evident that nitric oxide formation is far more sensitive to excess oxygen than it is to burner adjustments in this particular unit. Thus, the optimized mode of operation is to lower the excess air to a point just above the smoke and/or carbon monoxide limit. If we chose the carbon monoxide limit to be 100 ppm, then 3.0% excess oxygen would be the optimum operating mode.

Taking burners out-of-service to achieve off-stoichiometric (OS) firing (or staged combustion) is a technique often used in larger units for emissions control. However, on boilers the size of Alma Unit #3 this technique has limited application. Since there are only four burners to adjust, OS firing can only be achieved effectively at greatly reduced loads.

Four series of tests were run at Alma in which one of the upper burners was taken out-of-service to achieve OS conditions. In each case, gaseous emissions were measured before and after opening the air register on the inactive burner. The results are presented in Table 5.1-6.

It is concluded that nitric oxide emissions can be reduced by going to an off-stoichiometric mode. However, at high loads the CO emissions are unacceptably high due to the inability of the three active burners to successfully do the work of four burners. Also the coal grind is adversely affected in the OS mode.

TABLE 5.1-6. EFFECT OF STAGED COMBUSTION

Test No.	Boiler Capacity	Burner Configuration	Excess O_2, %	CO Dry, ppm	NO Dry, ppm	Reduction %
40 *	85%	Upper Right BOOS Air Reg. Closed	1.9	1536	361	23%
41 *		Upper Right BOOS Air Reg. Opened	2.2	1475	277	
38 *	74%	Upper Left BOOS Air Reg. Closed	2.4	78	472	43%
39 *		Upper Left BOOS Air Reg. Opened	2.3	1766	269	
51 *	57%	Upper Right BOOS Air Reg. Closed	4.9	35	528	32%
52 *		Upper Right BOOS Air Reg. Opened	4.1	37	361	
70 †	53%	Upper Left BOOS Air Reg. Closed	4.0	251	456	58%
71 †		Upper Left BOOS Air Reg. Opened	1.6	2000+	192	

*Eastern Coal
†Western Coal

5.1.4 Emissions

Emissions were either reduced or unchanged by the switch to Montana coal at Alma Unit #3. A summary of the Montana coals average effect on all emissions measured is given below:

Uncontrolled Particulates - 26% reduction
Controlled Particulates - 71% reduction
Sulfur Dioxide (SO_2) - 67% reduction
Sulfur Trioxide (SO_3) - Unchanged
Nitric Oxide (NO) - 18% reduction
Nitrogen Dioxide (NO_2) - Insignificant
Carbon Monoxide (CO) - Unchanged
Unburned Hydrocarbons (HC) - Unchanged

The emissions data is summarized in Table 5.1-7. This is followed by a discussion of each emissions category. Direct comparisons are made between the emissions from both fuels, and emissions were related to fuel properties whenever possible.

TABLE 5.1-7. EMISSION DATA SUMMARY, UNIT 3, DAIRYLAND POWER COOPERATIVE, ALMA, WISCONSIN

Test No.	Date	Load % Capacity (10^3lb/hr)	O_2 %	CO_2 %	CO (dry) ppm	HC (wet) ppm	NO		SO_x		SO_3		Fuel Sulfur Emitted %	Uncont. Part. ng/J (lb/10^6Btu)	Cont. Part. ng/J (lb/10^6Btu)	Dust Coll Eff. %	Comb. in Flyash %
							(dry) ppm	ng/J (lb/10^6Btu)	(dry) ppm	ng/J (lb/10^6Btu)	(dry) ppm	ng/J (lb/10^6Btu)					
1	5/29/75	87 (200)	2.9*	14.6	134	--	534	203 (0.472)	--	--	--	--	--	--	--	--	--
2	6/2/75	87 (200)	3.0	14.2	--	--	590	224 (0.521)	--	--	--	--	--	--	--	--	--
3	6/3/75	87 (200)	3.6	14.4	--	--	586	223 (0.518)	2805	2273 (5.288)	23.6	19.1 (0.044)	--	--	--	--	--
4	6/3/75	87 (200)	3.9	--	--	--	--	--	--	--	--	--	--	2207 (5.133)	11.61 (0.027)	99.47	--
5	6/4/75	87 (200)	3.9	--	--	--	--	--	3060	2480 (5.768)	20.7	16.8 (0.034)	--	1978 (4.600)	9.73 (0.023)	99.51	3.5
6	6/5/75	85 (196)	3.5	--	--	--	--	--	3160	2561 (5.957)	30.0	24.3 (0.057)	101	--	--	--	--
7	6/6/75	49 (112)	4.7	13.6	--	--	605	230 (0.535)	3007	2437 (5.668)	20.4	16.5 (0.038)	--	2236 (5.202)	10.83 (0.025)	99.52	--
8	6/9/75	87 (200)	2.0	13.2	--	--	574	218 (0.507)	--	--	--	--	--	--	--	--	2.3
9	6/10/75	57 (130)	4.0	14.6	--	--	491	187 (0.434)	3393	2750 (6.396)	286	232 (0.539)	94	3289 (7.649)	7.61 (0.018)	99.77	5.4
10	6/11/75	57 (130)	6.1	11.8	--	--	610	232 (0.539)	--	--	--	--	--	--	--	--	--
11	6/11/75	53 (122)	4.2	--	--	--	--	--	3932	3187 (7.412)	21.5	17.4 (0.041)	102	--	--	--	--
13	6/18/75	87 (200)	3.1	--	--	--	--	--	3343	2709 (6.302)	185	150 (0.349)	--	--	--	--	--
14	6/19/75	89 (205)	3.1	--	--	--	--	--	3563	2888 (6.717)	4.6	3.7 (0.009)	107	--	--	--	--
16	6/23/75	26 (60)	12.2	7.4	--	--	611	232 (0.540)	2602	2109 (4.905)	5.0	4.1 (0.009)	86	--	--	--	--
17	6/24/75	26 (60)	13.0	6.5	--	--	636	242 (0.562)	--	--	--	--	--	4119 (9.581)	--	--	9.3
18	6/24/75	26 (60)	12.8	--	--	--	--	--	--	--	--	--	--	3667 (8.529)	18.80 (0.044)	99.49	10.7

(continued)

TABLE 5.1-7 (continued).

Test No.	Date	% Capacity (10^3lb/hr)	O_2 %	CO_2 %	CO (dry) ppm	HC (wet) ppm	NO (dry) ppm	NO ng/J (lb/10^6Btu)	SO_x (dry) ppm	SO_x ng/J (lb/10^6Btu)	SO_3 (dry) ppm	SO_3 ng/J (lb/10^6Btu)	Fuel Sulfur Emitted %	Uncont. Part. ng/J (lb/10^6Btu)	Cont. Part. ng/J (lb/10^6Btu)	Dust Coll. Eff. %	Comb. in Flyash %
19	6/25/75	26 (60)	12.3	7.2	82	--	612	233 (0.541)	--	--	--	--	--	--	--	--	--
20	6/25/75	26 (60)	13.8	5.6	283	--	525	199 (0.464)	--	--	--	--	--	--	--	--	--
21	6/25/75	26 (60)	10.2	9.0	36	--	596	226 (0.527)	2075	2330 (5.420)	1.9	1.5 (0.004)	--	3705 (8.617)	14.69 (0.034)	99.60	4.9
22	6/26/75	54 (125)	5.0	13.8	18	--	543	206 (0.480)	--	--	--	--	--	--	--	--	--
23	6/27/75	55 (127)	4.4	13.9	20	--	429	163 (0.379)	--	--	--	--	--	2740 (6.374)	7.19 (0.017)	99.74	3.9
24	6/27/75	55 (127)	3.7	--	--	--	--	--	--	--	--	--	--	2200 (5.118)	--	--	5.2
25	6/30/75	87 (200)	3.8	14.6	23	--	616	234 (0.544)	--	--	--	--	--	--	--	--	--
26B	6/30/75	87 (200)	3.5	15.5	26	--	546	207 (0.482)	--	--	--	--	--	--	--	--	--
27B	6/30/75	87 (200)	3.5	15.4	20	--	509	193 (0.450)	--	--	--	--	--	--	--	--	--
33	7/9/75	87 (200)	2.4	--	--	--	--	--	--	--	--	--	--	2677 (6.227)	--	--	11.8
34	7/9/75	87 (200)	2.4	--	--	--	--	--	--	--	--	--	--	2285 (5.314)	--	--	8.7
35	7/9/75	87 (200)	2.4	--	--	--	--	--	--	--	--	--	--	1586 (3.688)	--	--	6.9
37*	7/14/75	65 (150)	3.1	15.1	21	30	466	177 (0.412)	--	--	--	--	--	--	--	--	--
38*	7/14/75	74 (170)	2.4	16.1	78	22	472	179 (0.417)	--	--	--	--	--	--	--	--	--
39*	7/14/75	74 (170)	2.3	16.4	1766	20	269	102 (0.238)	--	--	--	--	--	--	--	--	--
40*	7/15/75	85 (195)	1.9	16.3	1536	25	361	137 (0.319)	--	--	--	--	--	--	--	--	--

(continued)

TABLE 5.1-7 (continued).

Test No.	Date	% Capacity (10^3 lb/hr)	O_2 %	CO_2 %	CO (dry) ppm	HC (wet) ppm	NO		SO_x		SO_3		Fuel Sulfur Emitted %	Uncont. Part. ng/J ($lb/10^6Btu$)	Cont. Part. ng/J ($lb/10^6Btu$)	Dust Coll. Eff. %	Comb. in Flyash %
							(dry) ppm	ng/J ($lb/10^6Btu$)	(dry) ppm	ng/J ($lb/10^6Btu$)	(dry) ppm	ng/J ($lb/10^6Btu$)					
41*	7/15/75	85 (195)	2.2	15.5	1475	23	277	105 (0.245)	--	--	--	--	--	--	--	--	--
42	7/16/75	87 (200)	2.9	16.1	7	28	579	220 (0.512)	--	--	--	--	--	--	--	--	--
43†	7/16/75	87 (200)	3.2	15.9	14	22	594	226 (0.525)	--	--	--	--	--	--	--	--	--
44†	7/17/75	87 (200)	2.4	15.8	15	25	611	232 (0.607)	--	--	--	--	--	--	--	--	--
45†	7/17/75	87 (200)	3.4	15.0	16	19	687	261 (0.607)	--	--	--	--	--	--	--	--	--
46†	7/18/75	87 (200)	3.5	14.6	17	24	584	222 (0.516)	--	--	--	--	--	--	--	--	--
47	7/21/75	87 (200)	3.7	15.5	20	28	635	241 (0.561)	--	--	--	--	--	--	--	--	--
48†	7/21/75	87 (200)	3.1	15.8	20	28	542	206 (0.479)	--	--	--	--	--	--	--	--	--
49†	7/22/75	87 (200)	1.8	16.7	570	34	355	135 (0.314)	--	--	--	--	--	--	--	--	--
50†	7/22/75	87 (200)	5.2	13.2	20	28	690	262 (0.610)	--	--	--	--	--	--	--	--	--
51*	7/23/75	57 (130)	4.9	13.5	35	27	528	201 (0.467)	--	--	--	--	--	--	--	--	--
52*	7/23/75	57 (130)	4.1	14.9	37	17	361	137 (0.319)	--	--	--	--	--	--	--	--	--
53	7/23/75	57 (130)	6.2	12.5	63	41	646	245 (0.571)	3504	2840 (6.605)	23.6	19.1 (0.044)	95	2645 (6.152)	--	--	--
54	7/24/75	57 (130)	3.8	14.9	21	31	505	192 (0.446)	3748	3038 (7.065)	16.1	13.6 (0.030)	--	--	--	--	--
3LT	10/15/75	87 (200)	1.7	16.9	0	--	--	--	3329	2698 (6.275)	28.0	22.7 (0.053)	--	--	7.59 (0.018)	--	--
4LT	10/29/75	87 (200)	1.6	16.0	4000	--	--	--	2599	2106 (4.899)	11.3	9.2 (0.021)	--	2897 (6.739)	11.26 (0.026)	99.61	--

(continued)

TABLE 5.1-7 (continued).

Test No.	Date	% Capacity (10^{3}lb/hr)	O_2 %	CO_2 %	CO (dry) ppm	HC (wet) ppm	NO (dry) ppm	NO ng/J (lb/10^{6}Btu)	SO_x (dry) ppm	SO_x ng/J (lb/10^{6}Btu)	SO_3 (dry) ppm	SO_3 ng/J (lb/10^{6}Btu)	Fuel Sulfur Emitted %	Uncont. Part. ng/J (lb/10^{6}Btu)	Cont. Part. ng/J (lb/10^{6}Btu)	Dust Coll. Eff. %	Comb. in Flyash %
56	8/5/75	73 (168)	1.9	17.5	2000+	--	339	131 (0.305)	--	--	--	--	--	--	--	--	--
57A	8/6/75	74 (170)	5.7	13.9	16	30	695	269 (0.625)	913	754 (1.753)	53.9	44.5 (0.103)	--	1966 (4.572)	4.35 (0.010)	99.70	1.1
57B#	8/6/75	74 (170)	4.2	15.7	27	--	461	178 (0.415)	--	--	--	--	--	--	--	--	--
58#	8/7/75	74 (170)	3.9	14.2	16	22	560	217 (0.504)	1113	919 (2.137)	35.6	29.4 (0.068)	--	1687 (3.923)	2.22 (0.005)	99.87	--
59#	8/8/75	72 (166)	2.6	16.9	139	--	452	175 (0.407)	878	725 (1.686)	14.9	12.3 (0.029)	--	--	--	--	--
60#	8/11/75	76 (175)	2.8	15.8	163	--	438	169 (0.394)	--	--	--	--	--	1161 (2.099)	3.73 (0.009)	99.68	--
61	8/12/75	26 (59)	11.8	8.6	37	--	675	261 (0.607)	1941	1602 (3.727)	9.5	7.8 (0.018)	--	--	5.57 (0.013)	--	--
62	8/13/75	26 (60)	9.4	9.5	15	--	468	181 (0.421)	1162	959 (2.231)	13.8	11.4 (0.026)	--	2216 (5.155)	4.07 (0.009)	99.82	1.9
63#	8/14/75	57 (131)	2.8	16.4	126	24	342	132 (0.308)	1504	1242 (2.888)	17.6	14.5 (0.034)	74	--	--	--	--
64#	8/15/75	74 (170)	2.9	16.4	--	--	409	158 (0.368)	750	619 (1.440)	1.2	1.0 (0.002)	77	--	--	--	--
65	8/18/75	57 (130)	4.5	14.8	27	39	493	191 (0.444)	963	795 (1.849)	5.7	4.7 (0.011)	88	--	--	--	--
66	8/19/75	57 (130)	3.4	15.7	31	25	372	144 (0.335)	996	822 (1.912)	2.7	2.2 (0.005)	--	2895 (6.733)	1.66 (0.004)	99.94	1.0
67	8/20/75	57 (130)	3.5	14.6	23	23	410	159 (0.369)	--	--	--	--	--	2781 (6.468)	2.61 (0.006)	99.91	--
68	8/21/75	75 (173)	2.7	16.3	750	23	340	132 (0.306)	874	721 (1.678)	25.3	20.9 (0.049)	76	--	--	--	--
70*	8/25/75	52 (120)	4.0	15.4	251	--	456	176 (0.410)	--	--	--	--	--	--	--	--	--
71*	8/25/75	53 (121)	1.6	17.1	2000+	--	192	74 (0.173)	--	--	--	--	--	--	--	--	--

(continued)

TABLE 5.1-7 (continued).

Test No.	Date	% Capacity (10^3lb/hr)	O_2 %	CO_2 %	CO (dry) ppm	HC (wet) ppm	NO (dry) ppm	NO ng/J (lb/10^6Btu)	SO_x (dry) ppm	SO_x ng/J (lb/10^6Btu)	SO_3 (dry) ppm	SO_3 ng/J (lb/10^6Btu)	Fuel Sulfur Emitted %	Uncont. Part. ng/J (lb/10^6Btu)	Cont. Part. ng/J (lb/10^6Btu)	Dust Coll. Eff. %	Comb. in Flyash %
72	8/26/75	44 (101)	6.7	13.9	11	37	530	205 (0.477)	1243	1026 (2.387)	6.1	5.0 (0.012)	85	2679 (6.231)	3.75 (0.009)	99.86	1.2
73	8/27/75	41 (94)	5.0	13.8	31	28	386	149 (0.347)	937	773 (1.799)	2.3	1.9 (0.004)	98	1760 (4.094)	3.01 (0.007)	99.83	1.0
74	8/28/75	39 (90)	6.8	12.0	48	27	606	234 (0.545)	733	605 (1.407)	0.6	0.5 (0.001)	84	1721 (4.003)	4.11 (0.010)	99.76	--
75	--	70 (160)	5.8	--	--	--	--	--	712	588 (1.367)	4.6	3.8 (0.009)	76	--	--	--	--
76	--	70 (160)	3.8	--	--	--	--	--	750	619 (1.440)	2.8	2.3 (0.005)	86	--	--	--	--
78	--	48 (110)	4.8	--	--	--	--	—	790	652 (1.517)	1.9	1.6 (0.004)	90	--	--	--	--
LT-1	9/17/75	71 (163)	1.4	17.4	7000	--	512	198 (0.461)	906	748 (1.740)	26.6	22.0 (0.051)	--	2240 (5.211)	2.76 (0.008)	99.98	--
LT-2	10/1/75	74 (170)	2.3	16.5	0	--	--	--	1067	881 (2.049)	10.5	15.3 (0.036)	--	2702 (6.284)	2.33 (0.005)	99.91	--

§ = Burner air registers varied from normal for test purposes.

† = Burner diffusers varied from normal for test purposes.

* = Burners taken out of service to achieve off-stoichiometric firing.

Eastern Coal Test Numbers 1 - 4LT

Western Coal Test Numbers 56 - LT-2

Particulate Emissions--

Uncontrolled particulates (before ESP) were reduced an average 26% while controlled particulates (after ESP) were reduced 71% when Montana coal was burned. These reductions were the result of lower ash in the fuel, reduced ash carryover in the furnace and increased precipitator efficiency while burning the Montana coal. Average data for those tests in which both controlled and uncontrolled particulates were measured are shown in Table 5.1-8.

TABLE 5.1-8. AVERAGE PARTICULATE AND FUEL ASH DATA

Coal Type	Particulates Before ESP ng/J	Particulates After ESP ng/J	ESP Efficiency %	Ash In Fuel ng/J	Ash Carryover %
W. Kentucky	2832	11.49	99.59	6779	42
Montana	2096	3.28	99.84	5599	37
Difference	-26%	-71%	+0.25%	-17%	-10%

Uncontrolled particulate emissions are shown in Figure 5.1-5. Although there is considerable scatter in the data, the average 26% decrease in emissions is evident. Two-thirds of this decrease can be attributed to lower ash in the fuel, one-third to reduced ash carryover in the furnace. The noncoking characteristics of the Montana coal may account for the lower ash carryover. Slagging and fouling of the ash may also account for reduced carryover, especially at higher loads.

Controlled particulate emissions are shown in Figure 5.1-6. Montana coal emissions after the precipitator were an average 71% lower than Kentucky coal emissions. This can only be explained as an increase in precipitator efficiency. This increase in efficiency may have been related to a shift in

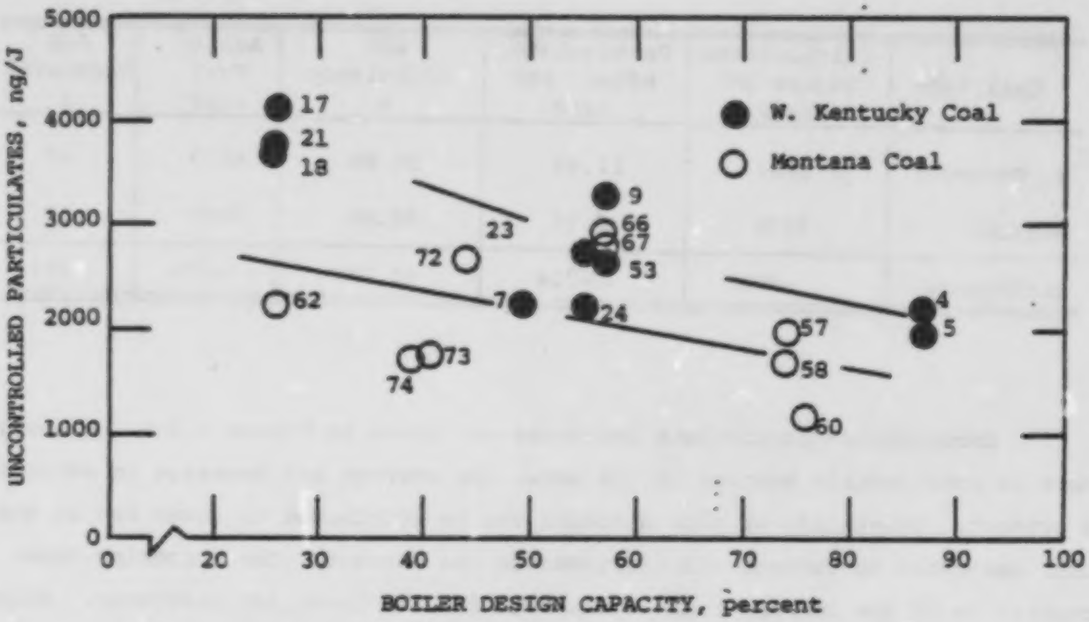


Figure 5.1-5. Uncontrolled particulates vs. boiler load, Dairyland Power Cooperative Unit 3.

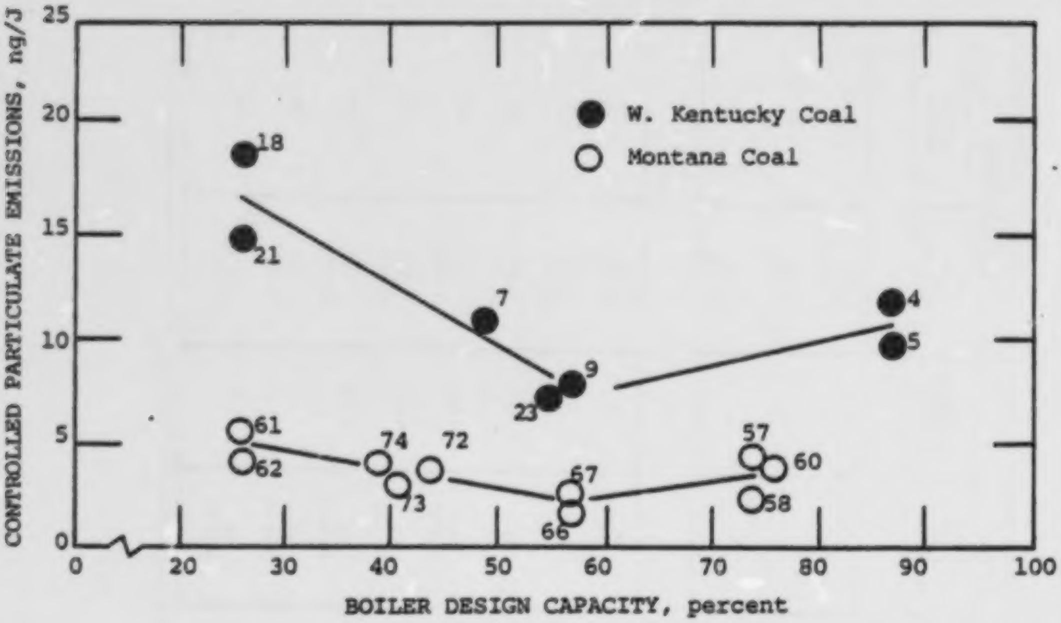


Figure 5.1-6. Controlled particulate emissions vs. boiler load, Dairyland Power Cooperative Unit 3.

particle size, or a decrease in fly ash resistivity. There were no discernable differences in sulfur trioxide emissions between the two fuels. However, carbon carryover was about 70% lower while burning the Montana coal. The combination of these two factors could have affected fly ash resistivity in favor of the Montana coal.

Sulfur Oxides Emissions--

Sulfur dioxide (SO_2) emissions were reduced an average 67% by burning Montana coal. These emissions were found to be invariant with unit load and excess oxygen. Sulfur trioxide (SO_3) emissions were found to be approximately the same for both fuels, although scatter in the data made it difficult to assess small differences with any degree of accuracy. Sulfur dioxide is plotted against boiler load in Figure 5.1-7.

The two most significant findings concerning sulfur emissions are: (1) the electrostatic precipitator efficiency was not decreased by the lower sulfur fuel, and (2) a significant portion of the sulfur (11-16%) was retained in the ash and, therefore, not emitted.

TABLE 5.1-9. SULFUR BALANCE SUMMARY, UNIT 3, DAIRYLAND POWER COOPERATIVE, ALMA, WISCONSIN

Test No.	Percent of Rated Capacity	O_2 percent	Sulfur in Fuel			Sulfur in Ash				Sulfur Emissions	
			Fuel Sulfur percent	HHV Fuel MJ/kg (Btu/lb)	As SO_2 ng/J (lb/10^6 Btu)	Ash Percent of Fuel	Sulfur Percent of Ash	As SO_2 ng/J (lb/10^6 Btu)	Retention percent	SO_2 ng/J (lb/10^6 Btu)	Fuel Sulfur Emitted percent
					W. Kentucky, River King Coal						
6	85	3.5	3.65	25,064 (10,776)	2,913 (6.774)	16.00	--	--	--	2,561 (5.957)	88
9	57	4.0	4.23	25,064 (10,776)	3,375 (7.851)	15.96	--	--	--	2,750 (6.396)	81
16	26	12.3	3.26	25.064 (10,776)	2,601 (6.050)	19.02	--	--	--	2,109 (4.905)	81
					Westmoreland, Montana Coal						
63	57	2.8	1.90	22.759 (9,785)	1,670 (3.883)	16.31	--	--	--	1,242 (2.888)	74
64	74	2.9	0.79	22.024 (9,469)	717 (1.669)	18.19	--	--	--	619 (1.440)	86
72	44	6.7	1.36	22.538 (9,690)	1,207 (2.807)	12.64	0.83	93	7.7	1,026 (2.387)	85
73	41	5.0	0.86	21.863 (9,400)	787 (1.830)	10.67	1.12	109 (0.254)	13.9	773 (1.799)	98
74	39	6.8	0.84	22.024 (9,469)	763 (1.774)	11.56	1.06	111 (0.259)	14.6	605 (1.407)	79
75	70	5.8	0.84	21.631 (9,300)	777 (1.806)	11.19	0.96	99 (0.231)	12.8	588 (1.367)	76
76	70	3.8	0.79	21.980 (9,450)	719 (1.672)	11.36	0.53	55 (0.127)	7.6	619 (1.440)	86
78	48	4.8	0.78	21.608 (9,290)	722 (1.679)	12.32	0.49	56 (0.130)	7.7	652 (1.517)	90

The results of a sulfur balance study are shown in Table 5.1-9. Based on this study, it was found that only 84% of the fuel sulfur was emitted from both coals. Approximately 11%, ±4% of the retained sulfur, was found in the fly ash (Montana coal only), while 0.4% was found in the bottom ash (not shown in the Table). The difference can be assumed to be errors in fuel analysis and/or nonrepresentative sampling.

As was found at Fremont Unit 6, discussed in Section 5.10, sulfur retention may be related to excess oxygen and load. More sulfur appears to be retained at the higher excess air conditions. Test number 72 is an exception to this case and more data is required before a definite conclusion can be drawn.

Nitric Oxide Emissions--

Nitric oxide emissions were found to be very sensitive to excess oxygen and only slightly sensitive to boiler load at Alma Unit #3. At similar load and excess oxygen conditions, the nitric oxide emissions were 10 to 20% lower on a higher heating value basis when Montana coal was burned. This reduction in nitric oxide formation may be partially due to the lower fuel nitrogen of the Montana coal as shown in the table below.

TABLE 5.1-10. RELATION OF FUEL NITROGEN TO NITRIC OXIDE EMISSIONS

Coal Type	Fuel Bound Nitrogen As NO ng/J	Average NO Emissions ng/J	% Fuel Nitrogen Conversion*
W. Kentucky	932	221	23.7%
Montana	720	181	25.1%
Difference	-23%	-18%	--

*Assuming total conversion of fuel-bound nitrogen

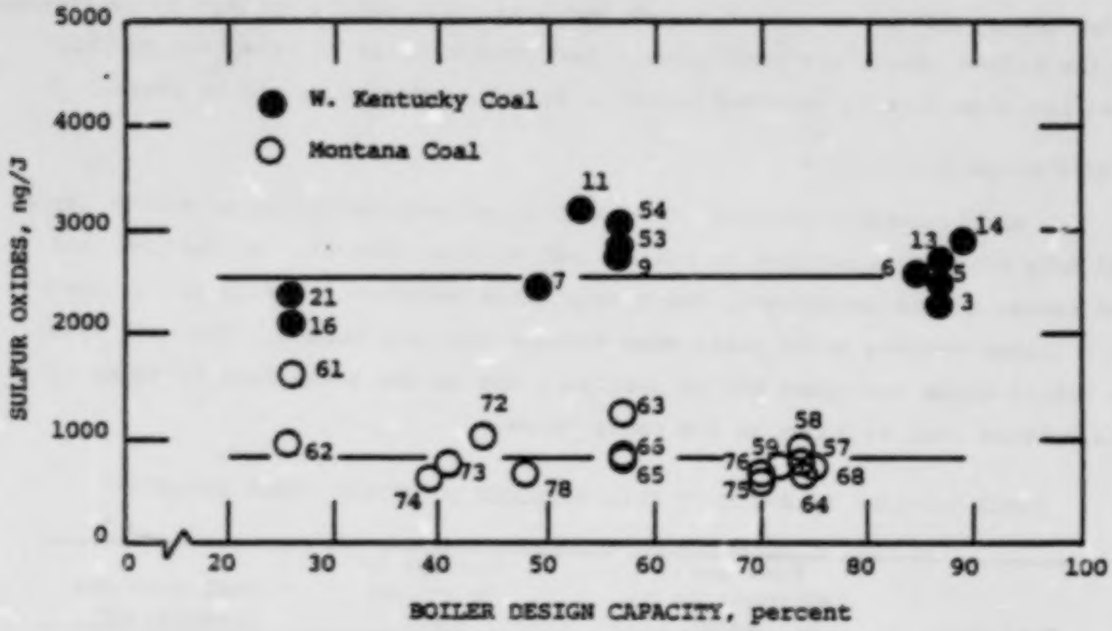


Figure 5.1-7. Sulfur oxides emissions vs. boiler, Dairyland Power Cooperative Unit 3.

Note that for the other pulverized coal unit studied, Fremont Unit 6, approximately 20% of the fuel bound nitrogen was assumed converted to nitric oxide for both fuels.

Nitric oxide is plotted against excess oxygen in Figures 5.1-3 and 5.1-4. The pronounced dependence on excess oxygen of this unit compared to Fremont Unit 6, and the higher average nitric oxide emissions indicate higher flame temperature. This condition could be rectified by modifying the burners to lower the flame temperature and, consequently, the emissions. Experiments with the burners' air registers, diffusers, and with staged combustion to lower the nitric oxide emissions are described in Section 5.1.3.

Nitrogen dioxide (NO_2) was measured but was found in such low concentrations, if at all, that it was not included in the emissions data summary. Generally, less than two parts per million NO_2 was found.

Carbon Monoxide and Hydrocarbon Emissions--

Carbon monoxide emissions increased significantly below 3% excess oxygen at high loads, and below about 12% excess oxygen at low loads. The former is due to oxygen starvation and the latter due to premature quenching of the flame. Between these two extremes, carbon monoxide emissions were found to be insignificant. Figure 5.1-8 illustrates the oxygen dependence. Boiler load, except for its relationship to excess oxygen, had no effect on carbon monoxide emissions. Neither did changing the fuel type.

Hydrocarbon emissions were consistently low in the range of 20 to 40 ppm, dry at 3% O_2. They did not appear to be a function of either load, excess oxygen or fuel type. Where measured, they are included in Table 5.1-7.

5.1.5 Boiler Efficiency

Alma Unit #3 experienced a 3.7% loss in boiler efficiency when Montana coal was burned. Most of this loss was due to moisture in the fuel (3.3%) and dry gas losses (1.4% at peak loads). The lower combustible loss of the Montana coal (1.0%) compensated for some of this efficiency loss. Table 5.1-11 summarizes the boiler heat losses for several tests on both fuels.

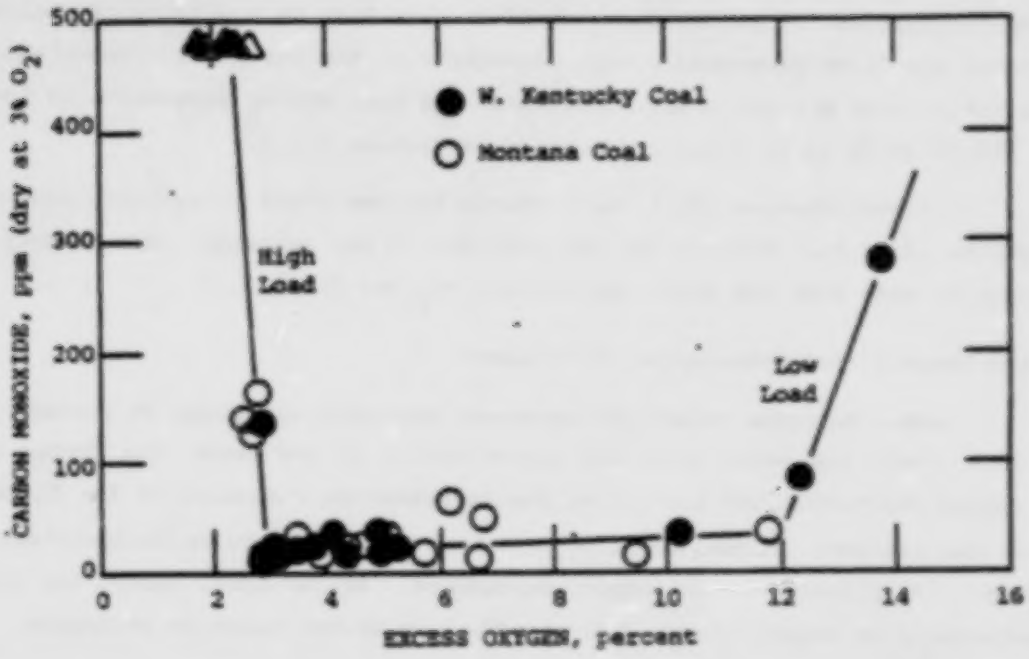


Figure 5.1-8. Carbon monoxide emissions vs. excess oxygen, Dairyland Power Cooperative Unit 3.

TABLE 5.1-11. BOILER EFFICIENCY SUMMARY, DAIRYLAND POWER COOPERATIVE, UNIT 3, ALMA, WISCONSIN

Test No.*	5	9	17	18	21	57	62	66	72
Test Load									
kg/s	25.3	16.4	7.5	7.5	7.5	21.4	7.5	16.4	12.8
% Capacity	87	57	26	26	26	74	26	57	44
Stack O_2 (% Dry)	3.0	3.4	12.7	12.6	10.3	5.7	9.4	3.4	6.7
Stack CO (ppm)	13.5	21.0	108.0	86.0	37.0	16.3	15.0	30.5	11.0
Stack Temp. (°K/°F)	443/338	416/290	408/275	411/280	416/290	447/346	429/312	433/320	433/320
Ambient Air Temp. (°K/°F)	316/109	321/118	334/141	336/146	334/142	314/105	324/124	311/100	321/118
Corr. Stack Temp. (°K/°F)	437/328	408/275	393/248	395/251	394/249	439/331	415/287	426/308	420/297
Boiler Heat Bal. Losses (%)									
Dry Gas	6.12	4.80	8.24	8.50	6.70	7.49	7.80	5.83	7.26
Moisture + H_2	5.16	5.06	5.00	5.01	5.00	8.42	8.28	8.35	8.31
Moisture in Air	0.15	0.12	0.20	0.21	0.16	0.18	0.19	0.14	0.18
Unburned CO	0.01	0.01	0.09	0.07	0.03	0.01	0.01	0.01	0.01
Combustibles	0.63	0.74	1.61	1.94	0.85	0.09	0.13	0.07	0.10
Radiation	0.50	0.76	1.70	1.70	1.65	0.58	2.53	0.76	0.98
Boiler Efficiency	87.44	88.52	83.15	82.56	85.61	83.23	81.06	84.83	83.17

*Test No. 5, 9, 17, 18, 21 are W. Kentucky Coal; Test No. 57, 62, 66, 72 are Montana Coal.

Boiler efficiency variation with load and fuel type is shown graphically in Figure 5.1-9. At low load (26% capacity) on eastern coal, a 2.5% increase in excess oxygen decreased boiler efficiency by the same amount, 2.5%. The increased heat losses were two-thirds dry gas loss and one-third combustible loss.

In order to improve the efficiency of western coal burning, the first order cure would be to pre-dry the coal. In the absence of this technology, improved heat recovery in the economizer and air heater sections would provide the most significant improvement. In designing new boilers to burn high moisture western coals, increased waterwall and/or boiler heating surface should be considered.

5.1.6 Conclusions and Recommendations

Alma Unit #3 successfully burned a high moisture sub-bituminous coal without boiler modification. The following advantages and disadvantages can be listed for such a fuel change:

Disadvantages

1. Decreased peak load capacity due to high superheat temperatures. 13% load restriction was experienced with Westmoreland coal.
2. Increased fouling in the superheat section.
3. Anticipated coal handling problems in the winter due to freezing of the coal.
4. Reduced heat rates due to moisture and dry gas losses.

Advantages

1. Greatly reduced sulfur oxide and particulate emissions.
2. Anticipated savings in fuel costs.
3. Because Dairyland Power is building a new coal fired unit at Alma, and because this unit will be burning western coal to meet new source emission requirements, it is advantageous to convert all Alma units to western coal. In this way, all of the facilities fuel could be delivered by unit train. Unloading and storage could be centralized. Man-hours in coal handling could be reduced.

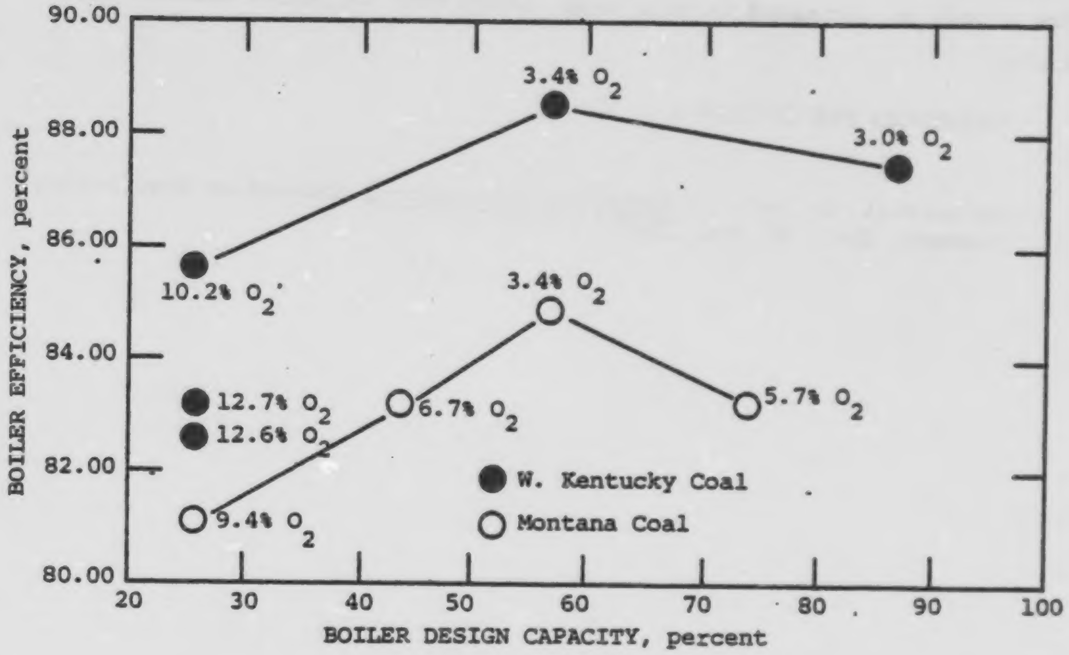


Figure 5.1-9. Boiler efficiency vs. capacity and coal type, Dairyland Power Cooperative Unit 3.

It would be advantageous to make modifications to Alma Unit #3 if a permanent change to western coal were anticipated. The most cost effective modification would be to remove sections of the superheat pendants. This could effect a reduction in superheat temperature and increase peak load capability. Improved steam attemperation would also help.

Fouling of the superheat pendants would be reduced by removal of alternate tube sections. In designing new units for western coals, tube spacing should be increased in this area, along with increased sootblowing capability.

REFERENCES FOR SECTION 5.1

1. de Lorenzi, O. (ed.), Combustion Engineering, Combustion Engineering Company, Inc., p. 7-8, 1947.

5.2 UNIROYAL BOILER #2

A series of tests were run on Boiler #2 to determine the feasibility of burning western coal on a multiple-retort underfeed stoker. The stoker on this unit had a long and unsuccessful history of western coal firing attempts. Plant personnel agreed to a short series of tests to determine if the stoker controls could be manipulated in a manner so as to accommodate the western coal. If a satisfactory firing mode was found, then a complete test series would be initiated and the whole plant would convert to the cheaper western coal.

A three day test sequence was run on Boiler #2. A specially ordered and prepared Wyoming coal was the test fuel. The western coal did not burn well in the boiler. The fuel bed was nonuniform, thin and not well established. High grate metal temperatures were recorded with a thermocouple matrix that was installed in the grate. Visual observations revealed that lower sections of the tuyere plates were completely exposed.

It was found that this type of stoker had inadequate undergrate air control. For burning a coking and agglomerating eastern type fuel the coal will self regulate the air flow distributions as the fuel burns. A free burning western coal, however, requires manual control over the air distribution, which was not available on Boiler #2.

A set of dampers installed beneath the tuyere grate area would permit better control over air distribution and would permit this type of stoker to fire a western coal.

5.2.1 Introduction

A preliminary series of tests were performed on Boiler #2 at the Uniroyal Company in Eau Claire, Wisconsin, to determine whether the further extensive type of test program was warranted. The unit tested at Uniroyal had a long and unsuccessful history of western coal burning attempts. Economics and unavailability of eastern type coals had forced Uniroyal personnel into experimenting with western coals during 1974-1975. Several western coals were tried in the boiler but none were burned successfully. The main problem common to all western type coals tested by Uniroyal were: inability to sustain ignition; raw fuel falling into ash pit and burning there; and insufficient ash protection of the grate area, thus causing sections of the grate to overheat and melt.

At the time Uniroyal was approached by KVB, Inc. to participate in this study, the availability problem Uniroyal initially had in obtaining eastern coal was no longer present. However, there was still some attractiveness in being able to successfully fire a cheaper western coal as opposed to their eastern fuels. Through discussions with Uniroyal, it was decided that due to their previous unsuccessful experience with western coal burning that a short preliminary study be conducted to determine if a small amount of specially prepared western coal could be fired in the unit. Two carloads were ordered. Little space was available for the western coal to be stored, therefore the test coal was burned directly after being unloaded from train cars.

The preliminary tests involved personnel from Uniroyal and KVB, Inc. The purpose was to try and successfully fire the unit with the test batch of western coal. If this test was successful, then Uniroyal would be willing to order additional western coal for a more comprehensive evaluation of the coal burning characteristics. No exhaust gas samples were taken during these tests. The main effort was aimed at keeping the boiler operating on the western coal and manipulating boiler control devices in an attempt to define a successful operating mode. A grate area thermocouple matrix was installed for the test run. One main concern of Uniroyal about attempting to burn western coal again, was that on one previous attempt the grate became overheated and failed, requiring an unscheduled unit outage and expensive repairs. Therefore, a grid of thermocouples were installed in the grate and monitored during the western coal tests.

The test burn took place over a three day period. Uniroyal personnel operated the boiler and KVB representatives observed the tests and made recommendations. All modes of possible boiler operation were attempted in an effort to continuously burn the western coal. None proved fruitful. However, much insight was gained as to why the western coal would not burn in this type of boiler. In addition, information and observations were made which suggested changes in this type of boiler which may make it possible to successfully fire western coal in the future.

5.2.2 Unit Description

Unit #2 tested at the Uniroyal Company Power Plant in Eau Claire, Wisconsin, is an underfed, multiple retort type boiler. It is fed by a Westinghouse Continuous Ash Discharge Link Grate Stoker. The tests took place November 5, 6, and 7, 1976. Figure 5.2-1 shows a side view of the stoker.

Boiler Description--

The boiler was manufactured by the Babcock and Wilcox Company in 1944. The Stirling type boiler has three steam drums and a single mud drum. Nameplate data for the boiler is 16.4 kg/s (130,000 pounds per hour) steam flow at a design pressure of 1.83 MPa (250 psig). The steam temperature is at the saturation temperature.

Combustion air is supplied by a forced draft fan. The unit is balanced draft and a slightly negative furnace pressure is maintained by an induced draft fan. The feedwater is preheated by an economizer in the back pass of the boiler.

The actual day-to-day operating conditions of the boiler have been reduced due to a retrofitted cyclone type dust collector and limited fan capacity. Current maximum continuous load for the boiler is about 12.6 kg/s (100,000 lb/hr) steam flow at about 1.65 MPa (225 psig) steam pressure.

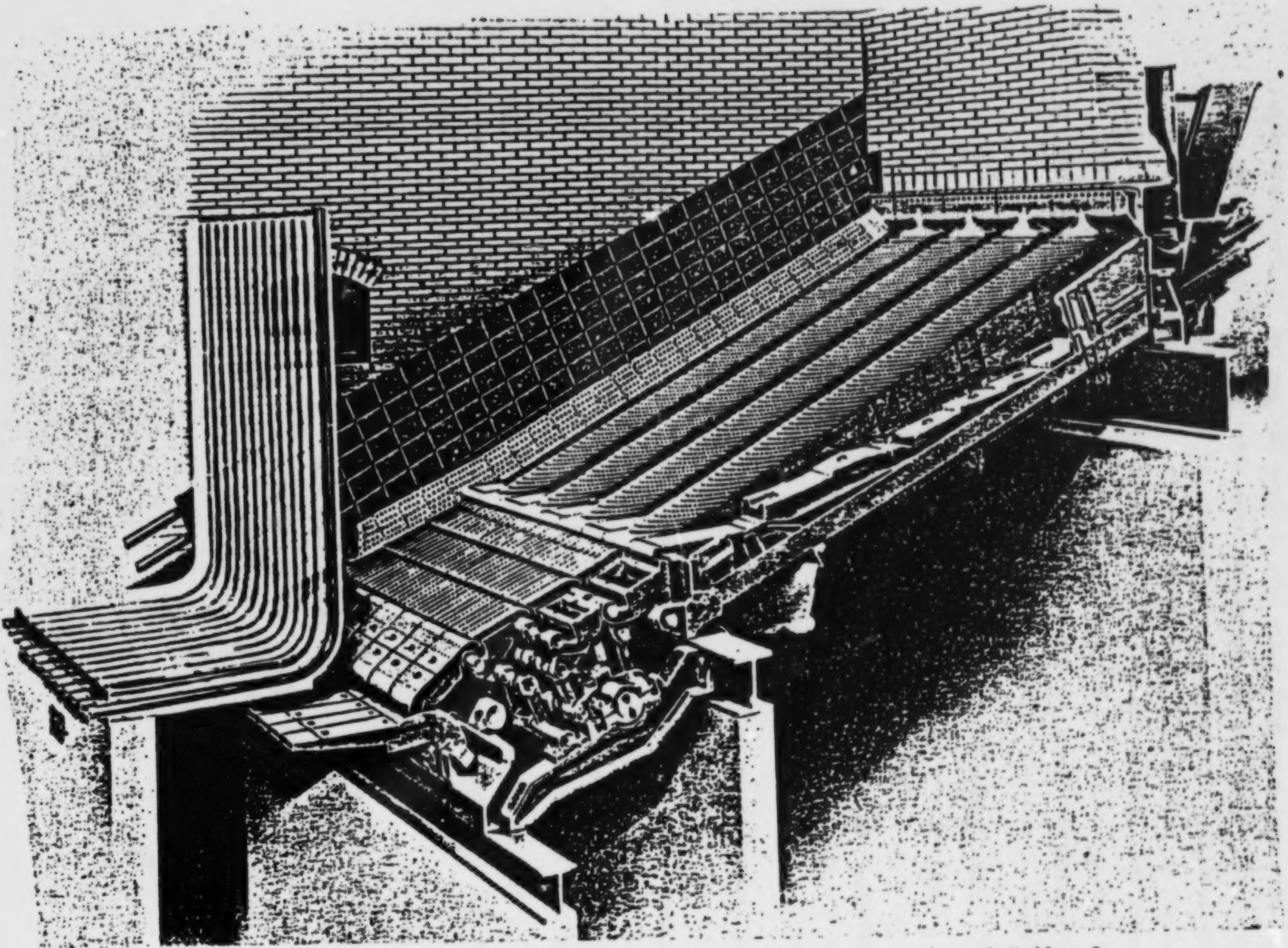


Figure 5.2-1. Multiple retort underfeed stoker with link grate, Uniroyal Boiler 2.

Stoker Description--

The furnace is supplied with coal by a multiple retort type underfed stoker built by the Westinghouse Corporation. Two conical coal distributors continuously supply raw coal to the Westinghouse Continuous Ash Discharge Link Grate Stoker. This stoker has eleven coal chutes or retorts into which raw fuel is pushed by eleven cylindrical rams. Between the retorts are ten rows of tuyeres which are plates stacked in a fish-scale-like fashion with holes in their outer surface through which combustion air is supplied. Figure 5.2-2 shows a reproduction of this type of stoker. The unit #2 stoker has an inclined grate of about 5.44 m (18 feet) in length. The tuyere section is 3.66 m (12 feet) long. The last 1.83 m (6 feet) are designated as the link grate section. At this section, combustion of the fuel should be almost completed and the undulating action of this section of the stoker forces the ash off onto the discharge end of the stoker and into the ash hopper.

The furnace section of the boiler is refractory lined. Neither the ram side or the ash discharge side of the stoker has an ignition arch.

Ram injection of the coal into the retorts is determined by the speed of the steam turbine driven crankshaft. The drive shaft has two speeds to govern fuel flow. The eleven retort feeding rams are separately attached to the drive shaft in groups of three, three, three, and two. A clutch type arrangement allows disengagement of sections of the rams to regulate fuel flow to different sections of the grate.

Combustion air is supplied through the tuyeres and link grate from below by the forced draft fan. The air is not preheated. A single damper regulates total air flow to the undergrate air chamber. A second damper in the undergrate plenum divides air flow between the link grate section of the stoker and the tuyere section. No other means of air distribution to the grate air is provided.

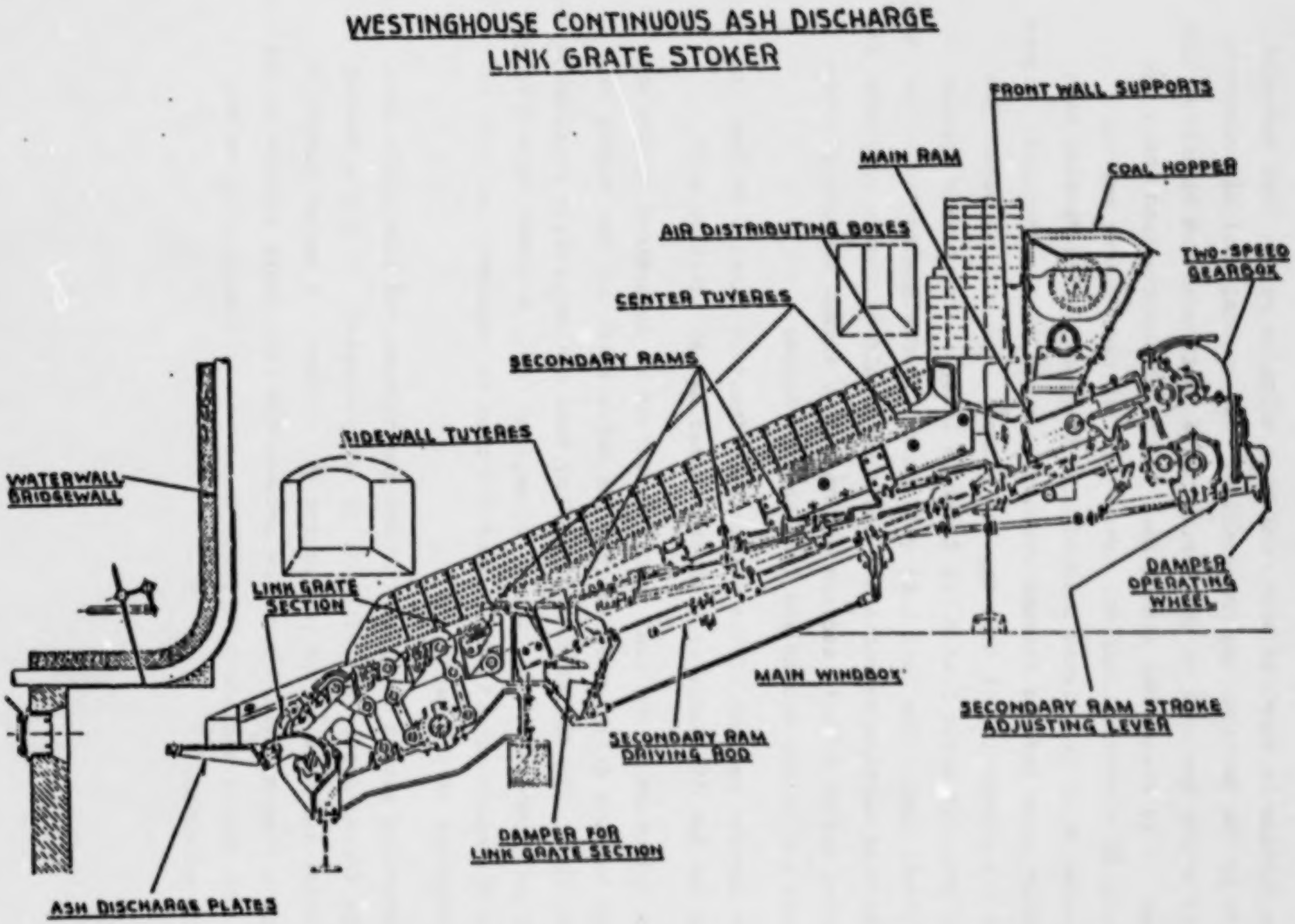

WESTINGHOUSE CONTINUOUS ASH DISCHARGE
LINK GRATE STOKER
FRONT WALL SUPPORTS
MAIN RAM
COAL HOPPER
AIR DISTRIBUTING BOXES
TWO-SPEED GEARBOX
CENTER TUYERES
SECONDARY RAMS
SIDEWALL TUYERES
WATERWALL BRIDGEWALL
LINK GRATE SECTION
DAMPER OPERATING WHEEL
MAIN WINDBOX
SECONDARY RAM STROKE ADJUSTING LEVER
SECONDARY RAM DRIVING ROD
DAMPER FOR LINK GRATE SECTION
ASH DISCHARGE PLATES

Figure 5.2-2. Cross-sectional view of stoker, Uniroyal Boiler 2.

5.2.3 Stoker Operation

Normal Design Conditions--

The Westinghouse Continuous Ash Discharge Link Grate Stoker is in the class of coal stokers known as the multiple retort underfed type. As the name underfed implies, fuel is supplied to the stoker from underneath. In the early development of underfeed stokers, the entire grate was of this type of fuel feeding configuration; however, design evolution of the underfed type stoker lead to the inclusion of a back section of grate area that actually is of an overfed type design. So the current designs might more correctly be called an underfeed-overfeed type stoker.

During normal operation of the stoker, raw coal is introduced into each of the eleven retorts at the front face of the furnace by the primary rams. These rams are cylindrical in shape and are attached to a large drive shaft on the outside of the boiler. The entire apparatus of cylindrical rams and drive shaft resemble a large internal combustion engine's crankshaft with oversized connecting rods and giant pistons. The primary rams feed raw coal continuously into the deep troughs of the retorts until coal begins spilling over the upper edges of the chutes and covers the tuyere sections. The coal over the tuyere section is ignited and combustion is mainly located in lanes running down the center lines of the tuyere rows. The combustion zones that follow the tuyere rows down the underfeed section of the grate are often referred to as burning lanes. Ideally, the burning lanes are well defined and narrow at the front end of the grate (where coal is initially introduced into the retorts) and become wider and start to merge into a single active fuel bed as they reach the end of the underfeed section and flow onto the link grate area. The retorts are designed so that they are deep at the ram end of the grate and decrease in depth as they decline towards the link grate section. At the link grate section, they are designed to essentially act as an overfed stoker for that area.

Normal combustion requires well defined burning lanes in the retort section of the grate that blend into a uniformly well established single fuel bed by the time the fuel reaches the link grate section. The main means of controlling fuel bed contour and movement in the retort section is with devices called secondary rams. These are pushing or moving sections located in the bottom plane of the retorts which use a reciprocating motion to help move the fuel bed forward and downward towards the link grate.

The secondary pushers or auxiliary rams located in the bottom of the retorts tend to even out the fuel bed as it travels downward. In Uniroyal boiler #2, each retort had two sets of secondary rams. These secondary rams are mechanically linked to the primary rams but can be individually adjusted to contour the fuel bed. Adjusting levers outside the boiler are provided to shorten or lengthen the individual stroke of each auxiliary ram.

Combustion air for this type of stoker is supplied from underneath through the tuyere rows and through the extension grate. A single forced draft fan forces the air into a windbox area under the retort section of the grate, and from this plenum chamber a single damper permits some air to be diverted rearward to the link grate area. This damper is split, so there is some control laterally from side to side on the undergrate section; but, the primary control is diversion of air to either the retort section or link grate section.

Burning Western Coals in Multiple-Retort Type Stokers--

The key to successful combustion of western coal in a multiple-retort underfeed type stoker is control of air distribution to the fuel bed. The noncoking, noncaking and free burning characteristics of western type coal demands precise placement of combustion air. The air distribution system is marginally adequate with coals for which the unit was originally designed. For western free-burning type coals the undergrate air control is inadequate.

Western coal burns freely, that is to say, each piece of coal will burn individually and not swell up and form large nonporous coke masses that are a common characteristic of an eastern type coal. In multiple retort type stokers, when an eastern type coal is initially introduced into the stoker, it is porous enough to allow air to freely flow through it, thus allowing intimate mixing of the fuel and air to start combustion. As the coal burns and travels downward, the eastern coal swells up, cokes, agglomerates and effectively presents an increasingly nonporous or resistive area for combustion air to penetrate. Hence, less air flows through the lower portion of the underfed (or retort) section of the stoker and most of the air continues to find its way into the inlet end of the coal stoker.

On the Uniroyal stoker, a single damper divides the undergrate air chamber into two sections, between the retort section and the link grate area. By the natural properties of coking and agglomerating the eastern coal self-regulates air distribution in the retort area of the grate. When the burning fuel bed reaches the link grate, the undulating action of this section breaks up the coke masses or any coking areas and effectively exposes more fuel surface area for completion of combustion. Regulation of the damper between the retort area and link grate plenum permits fairly adequate control of air into the link grate chamber. With eastern coal, one can adjust the damper to permit the appropriate amount of air into this section to complete final combustion.

Western coal burning on the Uniroyal multiple-retort underfeed type stoker presents a more difficult situation due to the nature of western coal burning properties and lack of sufficient air distribution control. As western coal enters the stoker, it is coarse and of sufficient porosity to permit the air to come in contact with the coal and begin combustion. However, as the coal burns, it does not form a nonporous mass of air resisting material. This is due to the free burning and nonagglomerating properties of western coal. This results in a fuel bed that as it moves towards the link grate is increasing in porosity and decreasing in resistance to air flow.

On this boiler the only way to control the western coal firing would be by increasing the control over the air distribution. Two air control modes are required. The first would be longitudinally, up and down the firing lanes. The second would be laterally or across the width of the stoker.

5.2.4 Test Series

Overview--

The test firing of western coal in Boiler #2 took place over a period of three days, November 5, 6, and 7, 1975. The boiler initially was fired on 100% eastern coal on November 5, and preliminary data and observations were made at that time. Data from the thermocouple grid was also taken at this normal operating configuration for comparison with western coal readings.

Table 5.2-1 presents a comparison of the two coals that were test fired in Boiler #2. The eastern coal was from West Kentucky and had a sulfur content of 2.5% and a higher heating value of about 28.8 MJ/kg (12,400 Btu/lb) as received. The western coal came from the Bighorn mine in Wyoming. It had been specifically ordered for these tests and had been carefully sized so that most of the fuel was 1-1/2 by 1 inch stoker coal. The fuel was also oil-treated to prevent dusting and help any fines in the coal adhere to the larger pieces. The western coal had a sulfur content of 0.61% and a higher heating value of 22.1 MJ/kg (9,500 Btu/lb) as received.

The switch over from 100% eastern coal and normal operation to western coal and modified operation occurred on November 6, 1976. On the previous day, the coal bunker had been allowed to burn down and, beginning in the early hours of the 6th, western coal was fed into Boiler #2 bunker. By morning, western coal began to reach the conical distributors and, by late morning, western coal was being fired in the stoker.

The remainder of November 6 was spent trying to maintain an acceptable fire on the stoker of Boiler #2 with 100% western coal. As long as the unit load demand remained somewhat steady, a marginally acceptable fuel bed was obtained. Unfortunately, Boiler #2 is used in a process plant where large fluctuations in load are present. Every time a load swing occurred, the marginal fuel bed would become unacceptable, and personnel would spend time trying to compensate for the changing conditions, only to have them change again once the initial correction was instituted.

TABLE 5.2-1.

CHARACTERISTICS OF COALS FIRED IN UNIROYAL BOILER #2

	BASE COAL - EASTERN	TEST COAL - WESTERN
Source	West Kentucky, Seam #9	Wyoming - Bighorn
Type and Size	1 1/4 x 1/4 Straight Run Stoker	1 1/2 x 1 Stoker
Preparation	Double Screened, Washed, No Fines	Oil Treated
	PROXIMATE ANALYSIS*	PROXIMATE ANALYSIS*
% Moisture	6.0 - 9.0	23.85
% Ash	7.0 -11.0	5.3
% Volatiles	37.0	32.36
% Fixed Carbon	40.0	38.49
HHV As Received MJ/kg	28.4	22.1
% Sulfur	2.5	0.61
Hardgrove Grindability	65	--
	ULTIMATE ANALYSIS+	ULTIMATE ANALYSIS+
% Carbon	68.21	57.37
% Hydrogen	4.81	4.07
% Nitrogen	1.26	1.01
% Chlorine	<0.01	<0.01
Ash Fusion Temp H=W	1440 °K (2133 °F)	1427 °K (2110 °F)
% Oxygen	8.46	11.41

* Proximate Analyses were obtained from Uniroyal personnel

+ Ultimate Analyses obtained from coals delivered to University of Wisconsin by same supplier as Uniroyal

Note: Table 5.2-1 is a comparison of the Eastern and Western coals which were used in the testing of Unit #2 at Uniroyal. Because the testing was of a much shorter duration then had been anticipated, and was, in fact, designed to determine whether it would be possible to undertake a full test program at this site, no coal samples were obtained. The data in Table 5.2-1 has, therefore, been obtained in part from Uniroyal personnel and, in part, from analysis of coal samples taken at the University of Wisconsin, Eau Claire, and the University of Wisconsin, Stout.

We feel confident in using the ultimate analysis of the coals sampled at the University of Wisconsin, Eau Claire and Stout facilities, as these tests were run during the same time frame and the coal was supplied to all three units by the same supplier, from the same stockpile.

Sometime during the period between the evening of the 6th and the morning of the 7th some eastern coal was inadvertently dumped into the bunker containing the western coal. Much of the morning was spent trying to contend with this situation. It became apparent that a blend of eastern and western coals did not work well together on this type of stoker.

The afternoon of the 7th resulted in the boiler marginally firing 100% western fuel again. The test personnel continued to vary operating parameters the remainder of the day in order to improve the western coal combustion. No successful firing mode was ever established. By the end of the 7th, eastern coal again began to enter the stoker, all the western coal had been consumed.

Thermocouple Configuration--

Boiler operators and Uniroyal personnel were especially concerned with stoker grate metal temperatures. A previous attempt to fire western coal on their underfeed stoker resulted in the overheating and failure of the grate around the link grate area. To help control and measure the grate temperatures, a twelve point thermocouple (T/C) matrix was installed in the grate area before the tests began. There, thermocouples were monitored during the tests and the data obtained is presented in this section.

Figure 5.2-3 presents a plan view of the thermocouple matrix configuration. The first four T/C's were installed in the link grate area and the remaining eight T/C's were placed in the tuyere area of the stoker. Figure 5.2-4 shows a detailed side view of the thermocouple installation. Figure 5.2-5 presents an even more detailed sketch of the T/C orientation in the tuyere plate area of the grate. The thermocouples were all installed as close to the surface of the grate area metal as possible so that true metal temperatures could be obtained.

Table 5.2-2 present the data obtained from the thermocouple grid during the course of the test sequence. Tests 1 to 5 show readings obtained during normal operation of Boiler #2 while firing the West Kentucky eastern coal. As can be seen, most areas on the tuyere sections are cool indicating a well

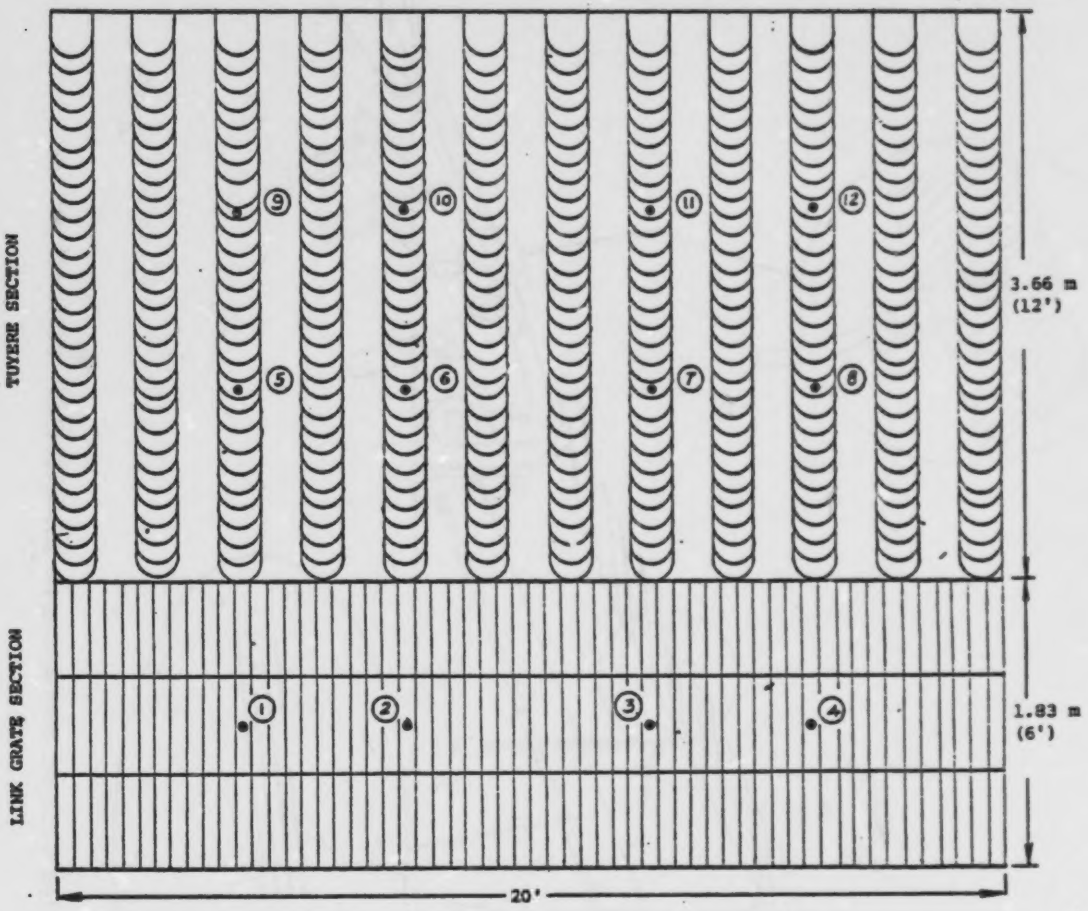

TUYERE SECTION
LINK GRATE SECTION
⑨
⑩
⑪
⑫
⑤
⑥
⑦
⑧
①
②
③
④
3.66 m (12')
1.83 m (6')
20'

Figure 5.2-3. Orientation of thermocouples on grate, Uniroyal Boiler 2.

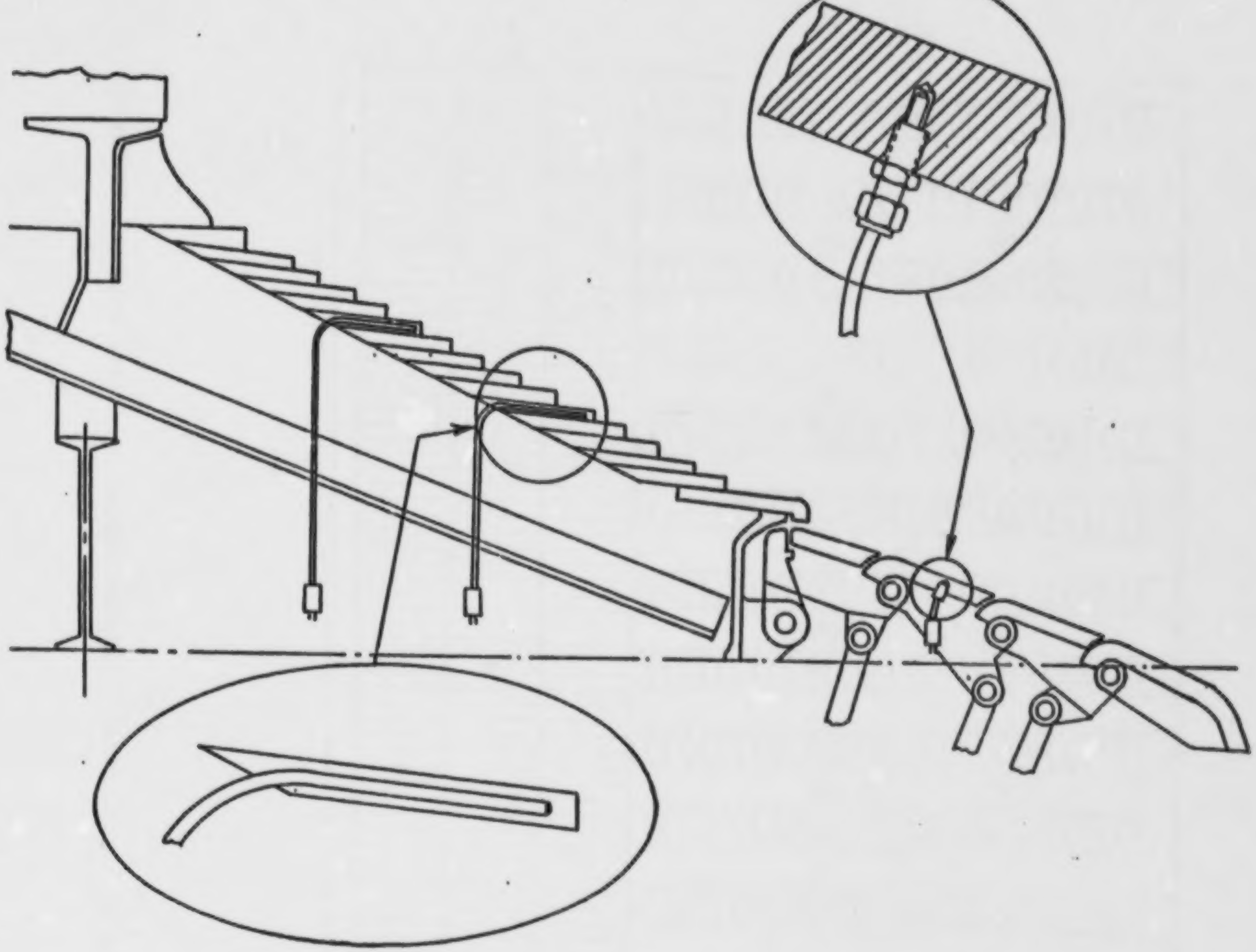
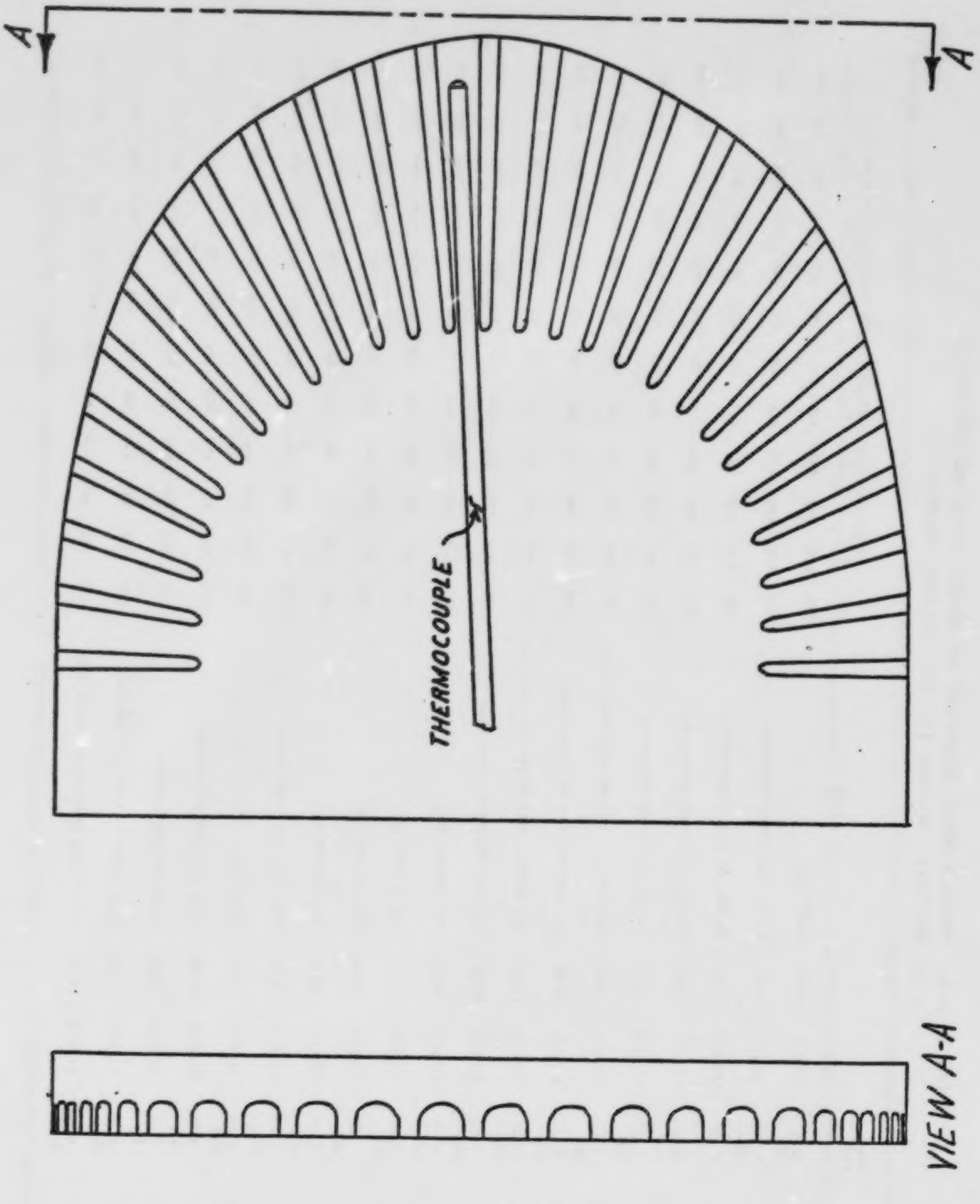


Figure 5.2-4. Detailed view of thermocouple installation, Uniroyal Boiler 2.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THERMOCOUPLE
VIEW A-A

Figure 5.2-5. Detail of tuyere plate with orientation of thermocouple probe, Uniroyal Boiler 2.

TABLE 5.2-2. THERMOCOUPLE READINGS OF GRATE METAL TEMPERATURES AT UNIROYAL BOILER #2, EAU CLAIRE, WISCONSIN

Test No.	Coal	Load kg/s (10^3 lb/hr)	Date	Time	Comments	Grate Location Temperatures, °K (see Figure 5.2-3) 1	2	3	4	5	6	7	8	9	10	11	12
1	East	3.15 (25)	11/5/75	10:15	No FD fan	710	488	600	533	316	322	339	327	461	455	400	389
2	East	6.30 (50)	11/5/75	10:55	FD fan on, normal operation	744	591	658	522	311	311	316	316	472	389	383	372
3	East	8.19 (65)	11/5/75	11:30	FD fan on, normal operation	666	611	672	544	314	311	311	311	566	422	455	394
4	East	8.19 (65)	11/5/75	1:15	FD fan on, normal operation	661	572	705	566	322	322	322	311	422	405	339	339
5	East	6.30 (50)	11/5/75	3:10	FD fan on, normal operation	722	477	664	533	322	311	316	325	394	400	389	389
6	Switch Over	6.93 (55)	11/6/75	9:08	Western coal on west side for 40 min.	550	477	436	444	300	327	383	316	327	333	311	316
7	Switch Over	6.93 (55)	11/6/75	10:00	All western coal in tuyere area	589	533	380	611	300	308	336	305	455	405	300	300
8	Switch Over	5.04 (40)	11/6/75	11:00	All western coal except for last foot	522	480	558	616	386	339	322	325	680	558	322	466
9	West	7.56 (60)	11/6/75	12:45	Tuyeres visible at lower edge	755	616	502	550	439	455	330	500	605	544	550	522
10	West	8.19 (65)	11/6/75	1:10	All western coal	733	677	561	658	464	461	386	739	694	555	625	525
11	West	8.19 (65)	11/6/75	1:53	All western coal	689	627	391	569	414	436	597	511	536	541	744	497
12	West	5.67 (45)	11/6/75	2:30	All western coal	666	691	544	700	600	516	614	564	633	658	880	572
13	West	8.19 (65)	11/6/75	4:20	All western coal	700	689	766	761	750	689	661	616	772	811	933	763
14	West	5.69 (45)	11/7/75	8:30	Poor fuel bed, dark zones	425	772	625	600	647	566	655	647	758	747	739	711
15	West	6.93 (55)	11/7/75	9:07	Mixed fuel	536	772	622	608	652	577	669	669	761	750	769	755
16	West	8.19 (65)	11/7/75	11:20	Fire lanes better defined	505	422	577	602	515	564	677	733	725	733	855	794
17	West	5.67 (45)	11/7/75	1:00	Grate surface visible	639	383	339	677	527	544	633	672	689	722	800	733
18	West	6.30 (50)	11/7/75	1:30	Fire lanes well defined but dark	644	511	350	677	566	533	608	664	561	705	766	727
19	West	6.93 (55)	11/7/75	2:30	Fire lanes improved but still dark	683	411	411	689	500	500	577	577	380	708	758	716

covered and protected grate. In the link grate area where combustion is fully developed and completed during normal operation, temperatures are somewhat higher. Still, overall metal temperatures are well below 755 °K (900 °F) which is considered a starting point for oxidation of the grate metal.

Tests 6, 7, and 8 present the readings obtained during the switch over from 100% eastern coal to 100% western coal from Bighorn, Wyoming. The western coal is first "seen" on the west-side of the boiler (or left side of plan view). This is noted by a rise in west side T/C readings on the upper tuyere plate T/C's. Test 8 has the grate almost completely covered by western coal except for the last foot or so of link grate. Temperatures are beginning to rise over the entire T/C matrixed area.

Tests 9 through 13 present thermocouple data from 100% western coal firing in Boiler #2 during November 6, 1975. All grate area metal temperatures are elevated above normal readings for eastern coal. Temperatures especially on the tuyere area are higher than normal. Temperatures in excess of 755 °K (900 °F) are noted in several areas. Sections of tuyeres are visible in lower areas of grate sections when one viewed the fuel bed during actual firing of coal.

November 7, 1975, thermocouple data is presented in Tests 14 through 19. Test 15 shows the grate area metal temperatures during the mix-up in eastern and western coal supplies. Temperatures continue to be excessively high contributing to oxidation and fatigue of grate metal. The last test, 19, shows eastern coal beginning to come down the stoker as seen by lowering of grate area temperatures at position #9.

In summary, grate area metal temperatures were significantly increased when the fuel was switched from eastern coal to western coal. The increase was caused by either lack of coverage of the metal by coal and ash or by the uneven and intense combustion in certain zones. Operators were unable to correct this situation with the available operating controls. A few weeks after the burning of the western coal, the weakened tuyere section of the grate which exhibited the excessively high temperatures failed and had to be replaced. Much overheating and metal oxidation damage was observed during the unscheduled outage. The damaged area included all the lower set of tuyere plates and the adjoining side plates that formed the retort chutes. The damaged areas occurred all across the bottom section of tuyeres and were not confined to the middle section or ends. The damaged zones corresponded to high temperature areas noted on the T/C grid and also to the zones of exposed tuyeres that could be observed visually through view ports at the back section of Boiler #2.

5.2.5 Results and Conclusions

Boiler #2 is equipped with an underfeed multiple-retort type stoker. This stoker was designed to burn an eastern type coal which cokes, agglomerates and cakes. Marginal undergrate air control is provided by means of a single air damper which effectively divides the air plenum into a tuyere section and a link grate section. With eastern coal burning, the fuel bed thickens and becomes more nonporous (and more resistive to air flow) as it travels downwards through the stoker. This is because the eastern coal swells-up and pieces stick together when the fuel burns and cokes. This "natural" self regulation of air distribution permits successful firing of eastern coal in this type of stoker.

A series of preliminary tests were performed on Boiler #2 to devise a firing mode to permit burning of a western coal on this type of stoker. Boiler #2 could not burn western coal successfully. Without sufficient under grate air control, burning western coal is difficult on an underfeed stoker. Western coal does not swell-up and form a nonporous mass when it burns. Instead, western coal is classified as free-burning, that is, each individual piece of coal will tend to retain its individual identity through the combustion process. This property of the fuel causes the fuel bed to become increasingly porous as it moves down the stoker. The more porous it becomes, the less resistive it is to air flow. This causes air to be diverted to lower regions of the stoker thus starving the inlet regions where more air is required. Without dampers or baffles underneath the grate in the air plenum to prevent this, the air will flow to the lower sections of the stoker. This extra air causes nonuniform combustion, unstable fires and overheating of the lower sections of the tuyere grate. In an extreme case, the grate may become uncovered and unprotected from radiation. The data gathered indicate that it may overheat enough to reach the oxidation point where there is the possibility of grate failure.

To fire western coal on a multiple-retort underfeed stoker requires more control of undergrate air distribution. A series of laterally arranged air dampers would help. Also, provision for biasing air up and down the stoker length would improve performance; although it would not be as important as being able to control air from inlet zones to lower tuyere zones.

5.3 UNIVERSITY OF WISCONSIN, STOUT

The third test site was at the University of Wisconsin, Stout, at Menomonie, Wisconsin. The boiler tested was Unit #2 of the Central Heating Plant on the university campus. This boiler supplied all the steam heating for the camput facilities but did not generate any power.

The test crew arrived at the test location on September 8, 1975, and prepared the sampling plan and test site for testing which began on September 10, 1975. Initial tests were run to determine temperature and pressure distributions in the sampling duct from which velocity determinations were to be made. Also, preliminary gaseous emission surveys were performed to determine if any stratifications existed within the exhaust duct. After the site set-up and preliminary flue gas measurements, actual testing began on September 12, 1975, and continued through November 7, 1975. A total of 36 tests were performed, 20 on western coal and 16 on eastern coal.

5.3.1 Boiler Description

The UW Stout boiler was manufactured in 1964 by the Wickes Boiler Company. The boiler supplies saturated steam for the university's steam heating/cooling system. This boiler is rated at 5.7 kg/s (45,000 lb/hr) steam flow. Actual operation of the boiler rates the unit at a 5 kg/s (40,000 lb/hr) steam maximum on a good eastern coal. Maximum steam pressure is 1.2 MPa (160 psig). Total boiler heating surface is 473.5 m^2 (5,097 ft^2). The water wall heating surface is 51.5 m^2 (554 ft^2). The boiler does not have an air preheater, and combustion air is supplied by a single forced draft fan from below the boiler. A second, smaller fan supplies air for overfire air above the grate area. Although the furnace is forced draft it is kept at a slightly negative pressure ~ -0.25 cm H_2O (~ -0.10 in. H_2O) by manipulation and adjustment of the furnace outlet damper. Natural draft is provided by the boiler's tall smokestack. The boiler does not have a superheater or economizer. Flue gas passes out of the furnace and through a cinder trap which removes some of the larger particles of dust. Remaining particles settle out by gravity as the exhaust gases flow through a long horizontal duct before exiting the smokestack for dispersion into the atmosphere.

5.3.2 Stoker Description

Stout Unit #2 represents a boiler class in the lower size range of interest of the EPA study and also is a boiler of interesting firing type. Stout #2 is fired by a vibragrate stoker manufactured by the Detroit Stoker Company of Monroe, Michigan, as illustrated in Figures 5.3-1 and 5.3-2.

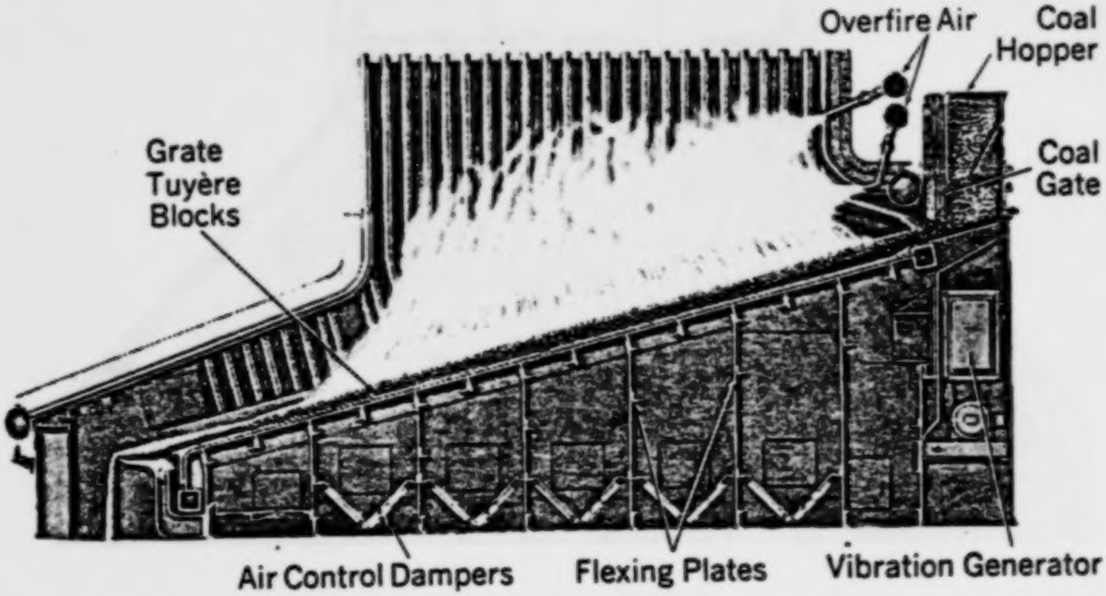

Overfire Air
Coal Hopper
Grate Tuyère Blocks
Coal Gate
Air Control Dampers
Flexing Plates
Vibration Generator

Figure 5.3-1. Water-cooled vibrating grate stoker.

Coal is conveyed from an underground storage bunker at the central heating plant via an enclosed conveyor belt and is dumped into a distributor above the stoker. From the distributor, coal is fed by gravity downward onto the grate area. Fuel bed thickness is regulated by an adjustable guillotine gate. Bed thickness is maintained at about 12.7 cm (5 in.). The grate area is horizontally inclined and is attached from below to a vibration generator. The grate is water-cooled by connection to the main boiler water circulation to prevent overheating. The vibration generator causes the entire grate area

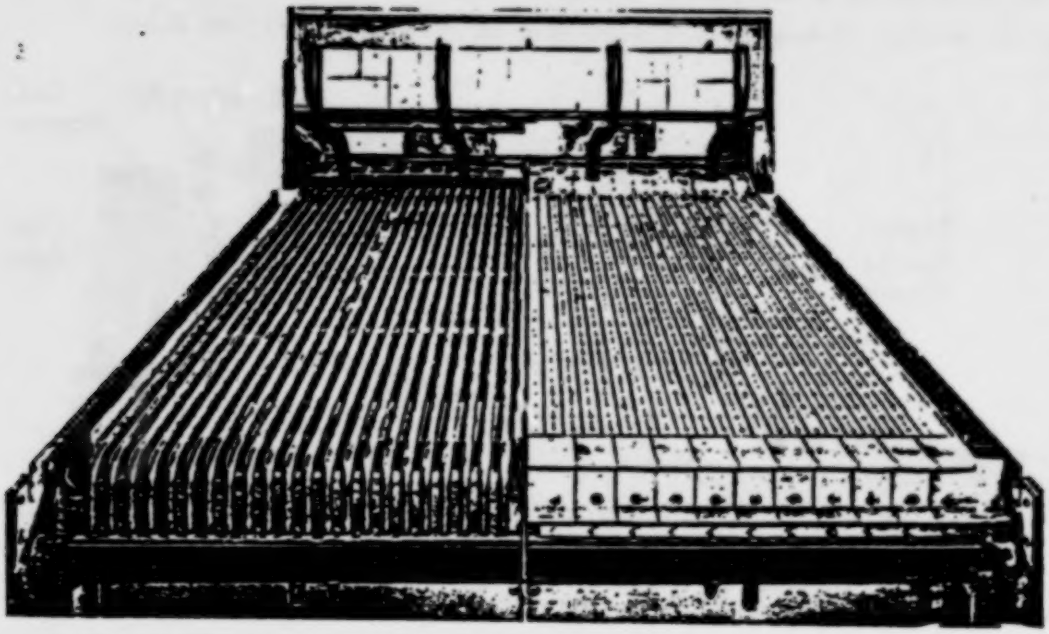


Figure 5.3-2. Front view section showing water-cooled grate.

to be agitated. The period and length of vibration can be adjusted. As load increases the period is shortened while the duration of vibration time is increased. The combination of vibrating grate area and gravity cause the fuel bed to travel downward from the coal inlet to the ash discharge end of the grate.

As coal enters the stoker, ignition is achieved by radiant energy reflected from the established fire via a short ignition arch. Combustion air is regulated from below by a series of undergrate air dampers. This stoker had five dampers and each was individually adjustable. Each damper controlled a zone that extended laterally across the stoker grate width. Additionally, air for completion of suspension burning was supplied by the overfire air ports located on the front wall. An adjustable ash dam plate retards ash discharge until combustion is complete. This also can help regulate fuel bed thickness although this is mainly determined by the fuel gate (guillotine) setting at the inlet side of the stoker. Several viewing ports are available along the length of the grate on both sides. The condition of the fuel bed can be observed and approximate adjustments in bed thickness or grate vibration duration and cycle time can be made as necessary.

Ash dumped off the grate is stored in a dry condition in hoppers below the boiler and is pneumatically removed periodically during the day.

5.3.3 Sample Site Location

Since Stout #2 did not have a dust collection device, only boiler outlet emissions were measured. After the flue gases exited the boiler, they made a horizontal pass through a long section of flue before beginning the final pass up and out of the chimney. Five sampling ports were placed in this long section of horizontal duct. The bottom sampling probe was completely covered with settled-out flyash which the test crew and plant personnel were unable to remove, hence only the top four ports were used for sampling. At each of the remaining four ports, three gaseous data collection probes were installed. One probe was placed at the centroid of equal areas of the duct. Each probe was of corrosion resistant 316 stainless steel and each probe inlet was fitted with a ten micron sintered stainless steel filter to prevent introduction of flyash into the gaseous sampling system. High temperature, inert, Type T, 9.5 mm (3/8 in.) nylon tubing connected each probe with the self-contained mobile test lab located just outside the central heating plant. Additionally, a heated Teflon sample line was strung from the mobile laboratory to the duct sampling location to enable measurement of hydrocarbons and the NO_2 component of NO_x.

Particulate sampling trains were carried to the sampling location and set up. A special cantilevered beam was hung to allow support for the Joy Manufacturing Company particulate sampling box during particulate tests. Also, a special support was built to handle the Shell-Emeryville SO_x sampling system which was used at the sample duct.

5.3.4 Comparison of Test Coals

Two different test coals were fired in the Stout #2 boiler. The first was a western low-sulfur coal from Bighorn, Wyoming. The second fuel tested was an eastern high-sulfur coal from West Kentucky. The two fuels are compared in Table 5.3-1.

5.3.5 Eastern Coal Burning on Vibragrate Stoker

A. Normal Stoker Operation--

Stout Boiler #2 was designed and built to burn a high Btu bituminous type coal. For this study, the previously defined eastern coal was from West Kentucky and had an average high heating value of 28.7 MJ/kg (12,340 Btu/lb). The coal was coarse and did not have over 30% fines. Normal combustion on the vibrating grate stoker is as follows:

Coal enters the inlet edge of the stoker through an adjustable guillotine gate. This gate height determines the depth of the fuel bed. For eastern coal this gate height or bed thickness is set at 10.16 cm (4 in.). Heat from the furnace radiates and re-radiates under the ignition arch at the inlet end of the stoker and ignites the raw coal. West Kentucky coal ignites well up into the arch and near to the gate. By the time the coal travels out

TABLE 5.3-1. COMPARISON OF TEST COALS FIRED AT STOUT BOILER #2

	Western Coal	Eastern Coal
FUEL:	Western Coal	Eastern Coal
LOCATION:	Kleenburn, Wyoming	Marlesville, W. Kentucky
MINE:	Big Horn	Vogue, Seam #11

Proximate Analyses

TEST	Western Coal		Eastern Coal	
% Moisture	17.80	18.43	9.02	9.47
% Ash	4.68	7.06	7.11	7.50
% Volatile	34.19	32.82	34.39	33.95
% Fixed Carbon	43.33	41.69	49.48	57.13
MJ/kg	24.1	23.0	28.0	28.0
Btu/lb	10378	9907	12028	12018
% Sulfur	0.83	1.23	3.41	2.60

Ultimate Analyses

TEST	Western Coal As Recd	Western Coal Dry	Eastern Coal As Recd	Eastern Coal Dry
% Moisture	21.53	xx	4.49	xx
% Carbon	56.76	72.33	71.36	74.71
% Hydrogen	4.13	5.26	5.03	5.27
% Nitrogen	0.91	1.15	1.28	1.34
% Chlorine	0.01	0.01	0.00	0.00
% Sulfur	0.83	1.06	2.81	2.94
% Ash	3.92	5.00	7.25	7.59
% Oxygen (by diff)	11.91	15.18	7.78	8.15

Mineral Analyses of Ash

	Western	Eastern		Western	Eastern
P_2O_5	0.59	0.11	MgO	4.80	0.78
SiO_2	29.82	45.77	SO_3	17.48	1.30
Fe_2O_3	8.18	25.81	K_2O	0.68	2.23
Al_2O_3	16.42	20.25	Na_2O	2.98	0.38
TiO_2	1.05	1.17	Undeter.	0.85	0.70
CaO	17.15	1.50			

Sulfur Forms

	Western Coal As Recd	Western Coal Dry	Eastern Coal As Recd	Eastern Coal Dry
% Pyrites	0.11	0.14	1.39	1.46
% Sulfate	0.02	0.03	0.06	0.06
% Organic	0.70	0.89	1.36	1.42
% Total Sulfur	0.83	1.06	2.81	2.94

Fusion Temperature of Ash

	Western Coal Reducing °K	(°F)	Western Coal Oxidizing °K	(°F)	Eastern Coal Reducing °K	(°F)	Eastern Coal Oxidizing °K	(°F)
Initial Deform.	1416	(2090)	1458	(2165)	1405	(2070)	1610	(2440)
Softening (H=W)	1430	(2115)	1469	(2185)	1466	(2180)	1644	(2500)
Softening (H=1/2 W)	1447	(2145)	1480	(2205)	1521	(2280)	1671	(2550)
Fluid	1461	(2170)	1491	(2225)	1577	(2380)	1697	(2595)

of the covering of the arch, combustion is well established. The grate is at an inclination to the horizontal and is attached from beneath to a vibration generator. By a combination of gravity and the shaking motion of the grate, the fuel bed moves slowly down the stoker. For eastern fuels, the length of time between vibrating periods is somewhat longer than for western coals and the duration of the shaking is generally shorter. The active burning length of the fuel bed using eastern coal does not extend as far along the stoker length as western coal.

Undergrate air dampers have a definite pattern when firing West Kentucky coal. Usually, most of the air is introduced into the second and third air zones when firing eastern coals. The first zone is closed and the last two zones (4 and 5) are opened somewhat. The flames are usually heavy and contain more orange color than a similar western coal fire. The fuel bed will also coke and swell. Clinkers may form from time to time and must be removed with a hand rake. Generally, combustion is completed well before the ash dam discharge end of the stoker is reached.

B. Eastern Coal Firing Exhaust Gas Emissions--

Table 5.3-2 contains a summary of the measured emissions for Stout #2 on both western and eastern coal.

Figure 5.3-3 presents the as-found excess oxygen versus boiler load characteristics for Stout #2. The excess O_2 tends to decrease with increasing load as expected. Also shown is the maximum load obtained on the unit with eastern coal. The maximum load obtainable on the West Kentucky coal was 5.5 kg/s (44,000 lb/hr) steam flow at an excess O_2 reading of 4.7%. Carbon monoxide emissions were high at this point and averaged 1120 ppm at 3.0% O_2 across the flue gas duct. Maximum load was determined by the inability to maintain a clear stack and by excessive CO emissions. Essentially, the natural draft of the furnace limited an increase in load since furnace pressure was becoming difficult to maintain. Additionally, heavy smoke would appear during grate vibration.

TABLE 5.3-2. EMISSION DATA SUMMARY, UNIVERSITY OF WISCONSIN, STOUT BOILER #2

Test No.	Date 1975	Load		O_2 (%)	CO (ppm)	CO_2 (%)	NO(dry) (ppm)	NO_x (wet) (ppm)	% Combust.	Particulates		SO_x (ppm)	SO_x		Fuel S		Sulfur Retention Factor, %
		kg/s	10^3 lb/hr							(ng/J)	lb/MBtu)		(ng/J)	lb/MBtu)	(ng/J)	lb/MBtu)	
									WESTERN COAL								
1	9/12	2.46	19.5	7.8	30.	12.	---	---	--	---	---	---	---	--	---	---	--
2	9/15	2.71	21.5	6.4	36.7	12.9	---	---	--	---	---	658	559	1.3	---	---	--
3	9/16	2.27	18.0	6.7	30.6	12.6	141	---	--	301.9	0.702	485	412	0.96	---	---	--
4	9/17	2.14	17.0	9.4	25.	10.4	179	148	--	---	---	525	446	1.04	688	1.6	76.3
5	9/18	2.14	17.0	9.8	30.	9.7	192	---	--	---	---	---	---	--	---	---	--
6	9/19	2.18	17.3	9.7	47.5	9.6	168	---	--	202.0	0.4697	---	---	--	---	---	--
7	9/22	1.03	17.0	7.3	14.	11.4	179	---	--	---	---	---	---	--	---	---	--
8	9/23	3.28	26.0	6.9	41.	12.5	160	156	--	---	---	650	553	1.285	---	---	--
9	9/24	1.89	15.0	6.5	--	12.9	143	---	--	---	---	---	---	--	---	---	--
10	9/25	3.34	26.5	7.5	--	11.9	176	---	--	190.7	0.4434	---	---	--	---	---	--
11	9/26	4.16	33.0	4.5	--	14.2	160	---	--	---	---	485	412	0.959	---	---	--
12	9/29	3.21	25.5	5.2	111.	13.9	146	---	45.5	242.5	0.564	---	---	--	---	---	--
13	9/30	3.21	25.5	5.7	84.	13.4	163	---	--	---	---	513	436	1.014	---	---	--
14	10/1	3.15	25.0	9.3	30.	9.9	192	197	17.3	310.4	0.7218	687	584	1.358	722	1.68	80.8
15	10/2	4.47	35.5	7.5	94.	11.9	176	---	--	---	---	833	708	1.647	1066	2.48	66.4
16	10/3	1.95	15.5	7.9	18.	11.1	197	---	--	---	---	476	405	0.941	---	---	--
17	10/6	2.01	16.0	8.7	108.	10.6	206	---	48.5	125.	0.2908	---	---	--	---	---	--
34	11/4	3.50	30.0	7.8	2000+	11.1	156	---	43.9	97.3	0.2263	683	581	1.35	---	---	--
35	11/5	3.78	30.0	7.8	2000+	10.6	158	---	--	---	---	606	515	1.198	---	---	--
36	11/7	3.72	29.5	6.3	2000+	11.5	143	---	--	---	---	709	603	1.402	671	1.56	90.
									EASTERN COAL								
18	10/8	1.89	15.0	10.2	38.	8.75	206	205	--	---	---	---	---	--	---	---	--
19	10/9	1.89	15.0	9.9	32.	8.9	201	203	--	176.	0.4096	2258	1919	4.46	2438	5.67	78.7
20	10/10	2.52	20.0	8.2	48.	10.6	187	204	--	---	---	2304	1958	4.55	---	---	--
21	10/13	1.89	15.0	10.5	36.	8.6	222	221	--	175.	0.4073	---	---	--	---	---	--
22	10/14	1.89	15.0	10.3	42.	--	195	---	--	---	---	2308	1962	4.56	---	---	--
23	10/15	1.89	15.0	9.0	31.	10.5	173	---	--	146.	0.3385	---	---	--	---	---	--
24	10/16	3.02	24.0	8.0	18.	--	195	---	--	---	---	2550	2167	5.04	---	---	--
25	10/17	5.04	40.0	5.4	--	--	221	---	--	---	---	2447	2105	4.9	---	---	--
26	10/17	1.89	15.0	9.5	--	--	211	---	--	---	---	2532	2152	5.01	---	---	--
27	10/20	3.03	24.0	11.5	295.	10.2	211	229	--	457.	1.0635	1804	1533	3.57	1860	4.326	82.
28	10/21	2.27	18.0	10.2	--	9.0	214	---	--	---	---	2416	2054	4.78	---	---	--
29	10/22	2.64	21.0	8.8	--	10.2	219	223	--	---	---	2441	2075	4.83	---	---	--
30	10/23	1.76	14.0	10.5	54.	8.5	237	236	51.6	220.	0.5118	2578	2191	5.10	---	---	--
31	10/28	5.54	44.0	4.7	1120.	14.0	185	232	--	---	---	2325	1976	4.60	1862	4.331	105.8
32	10/29	5.54	44.0	4.7	--	--	---	---	45.8	441.	1.0349	--	--	--	---	---	--
33	10/30	3.78	30.0	8.2	23.	11.0	187	228	44.4	276	0.6412	--	--	--	---	---	--

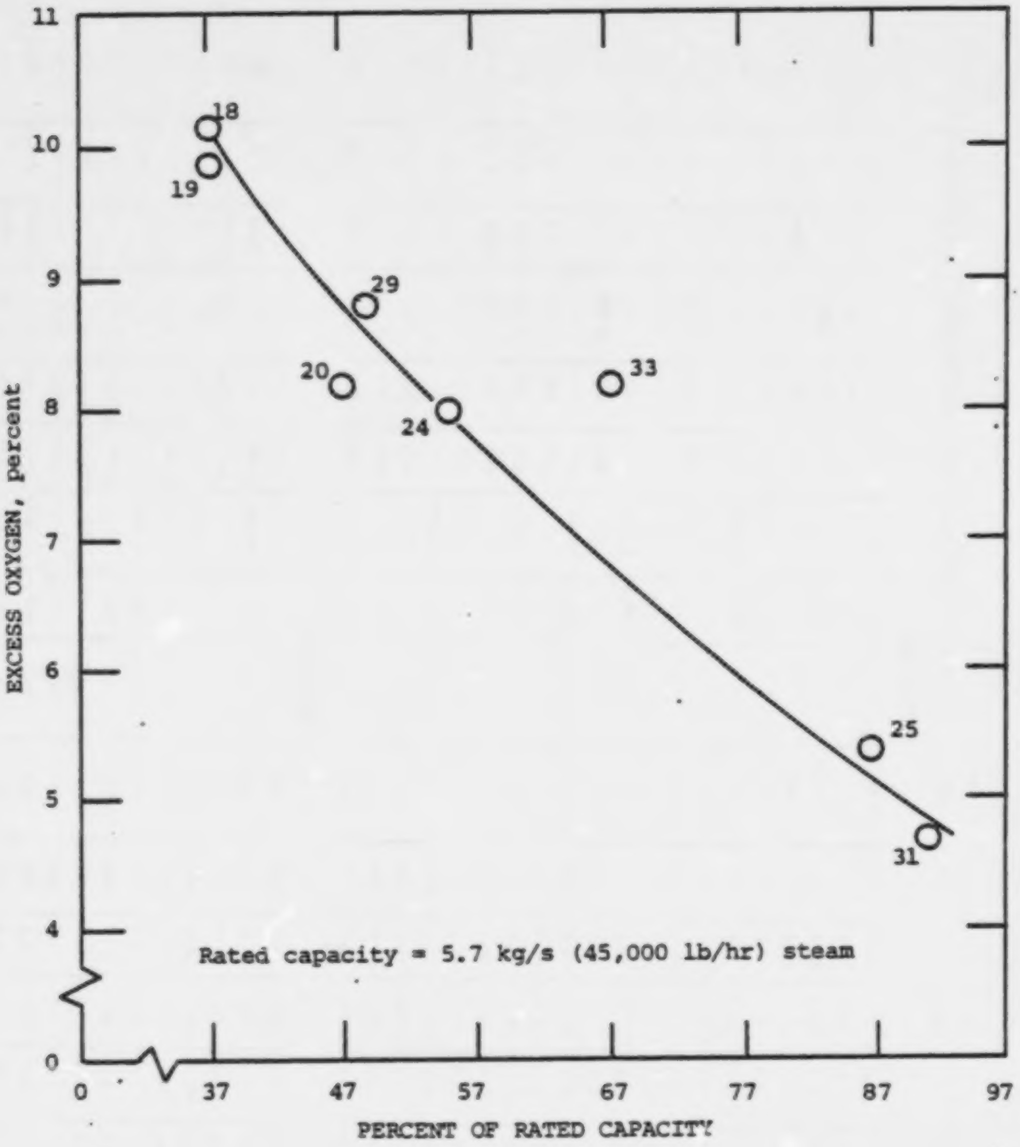


Figure 5.3-3. Load vs. excess oxygen, as-found operation, Stout Boiler 2, West Kentucky coal.

Sulfur oxides and particulate data were obtained at this maximum load of 5.5 kg/s (44,000 lb/hr) steam flow. Total sulfur oxides measured were 2325 ppm at 3.0% excess O_2. SO_3 was about 1.0% of the total SO_x measured. Particulates taken at maximum load were measured at 441 ng/J (1.0349 lb/MBtu).

NO and NO_x at maximum load were 185 ppm and 232 ppm at 3.0% O_2 respectively. Some hydrocarbons were measured at about 15 ppm at 3.0% O_2.

Figure 5.3-4 presents the as-found SO_x emissions for Stout #2 versus load for normal operation. Table 5.3-3 presents the summary of all SO_x data taken on West Kentucky coal. Emissions based on the fuel analysis of an average fuel sulfur content of 2.94% S and higher heating value of 29 MJ/kg (12,975 Btu/lb) would yield 2110 ppm.

Figure 5.3-5 presents the SO_x emissions as a function of excess oxygen for various boiler loads. No particular trend seems to be present with either load or excess O_2.

Figure 5.3-6 presents the NO emissions for Stout #2 as a function of load for the as-found normal operating conditions. The emissions appear to be quite constant with load. The average value of NO is 197 ppm at 3.0% excess O_2 in the as-found condition. Figure 5.3-7 presents the variation of NO emissions with excess oxygen level at various loads. NO formation shows a definite dependency on excess oxygen level at all loads. The curves show NO increasing sharply with small changes in excess oxygen.

Figure 5.3-8 presents the carbon monoxide emissions over the Stout #2 load range in the as-found condition. CO emissions were generally quite low (less than 100 ppm) except for the maximum load point of 5.5 kg/s (44,000 lb/hr) steam flow. Figure 5.3-9 presents the CO emissions as a function of excess oxygen at various loads. At the excess air levels tested, the CO emissions remained quite low except for the previously mentioned maximum load point.

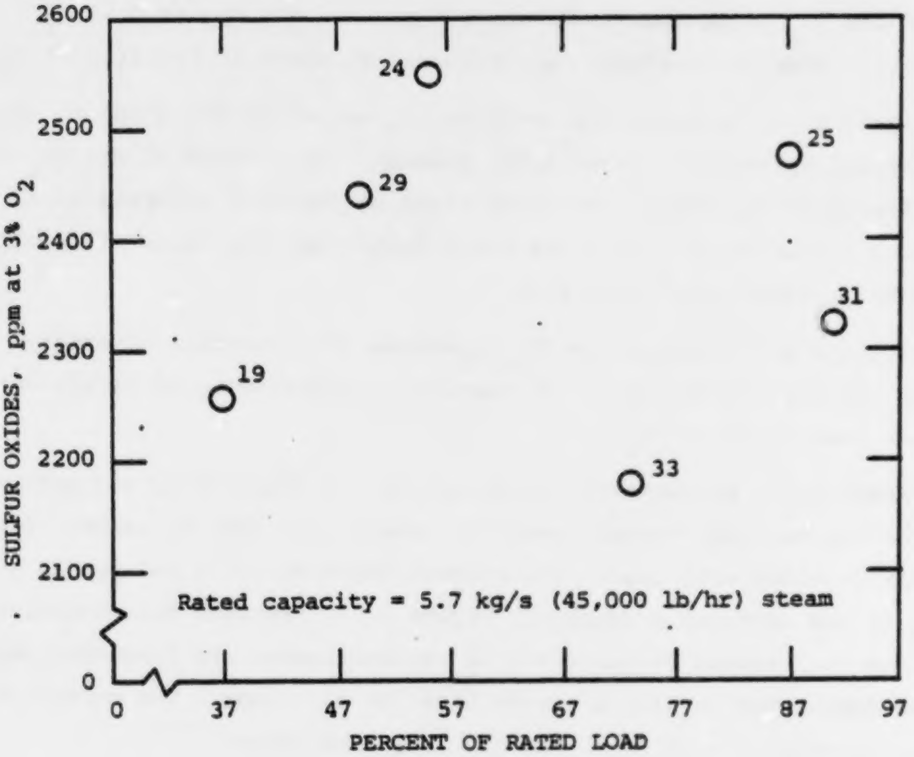


Figure 5.3-4. Load vs. SO_x emissions, as-found operation, Stout Boiler 2, West Kentucky coal.

TABLE 5.3-3. SO_x DATA SUMMARY, UNIVERSITY OF WISCONSIN, STOUT BOILER #2, WEST KENTUCKY COAL

Test No.	Load		O_2	SO_2 (uncorr. ppm)	SO_3 (uncorr. ppm)	SO_x (uncorr. ppm)	SO_2 (corr. ppm)	SO_3 (corr. ppm)	SO_x (corr. ppm)	Test Description
	kg/s	(10^3 lb/hr)	(%)							
19A	1.9	15.0	10.0	1391.9	14.4	1406.3	2277.6	23.6	2301.2	Low load, norm O_2
19B	1.9	15.0	10.0	1323.2	15.5	1338.7	2164.9	25.4	2272.1	" " " "
19C	1.9	15.0	10.0	1329.7	15.0	1344.	2175.9	24.5	2200.1	
20A	2.5	20.0	9.0	1788.	17.9	1805.9	2682.0	26.9	2708.9	Med load, norm O_2
20B	2.5	20.0	9.0		Backwashed	Sample				
20C	2.5	20.0	7.2	1433.3	22.8	1456.1	1869.5	29.7	1899.2	
22A	1.9	15.0	10.7	1333.	18.3	1351.	2330.	32.	2362	Low load
22B	1.9	15.0	10.7	1171.6	144.	1315.6	2047.4	251.6	2299.0	" "
22C	1.9	15.0	10.7	1238.5	57.3	1295.8	2164.4	100.	2264.4	" "
27A	3.0	24.0	11.6	901.3	16.0	917.3	1722.	30.5	1752.5	Med load
27B	3.0	24.0	11.3	1020.7	21.4	1042.1	1884.	39.5	1923.5	" "
27C	3.0	24.0	7.9	1239.	27.	1266.	1700.	37.	1737.	" "
28A	2.3	18.0	9.5	1309.	34.	1343.	2049.	53.2	2102.2	Low load
28B	2.3	18.0	10.63	1511.7	49.	1560.7	2624.	85.	2709.	" "
28C	2.3	18.0	10.75	1358.	30.2	1388.2	2384.8	53.	2437.8	" "
29A	2.7	21.0	8.5	1604.	34.8	1638.8	2310.	50.	2360.	Med load
29B	2.7	21.0	8.75	1653.	37.9	1590.9	2429.	55.7	2484.7	" "
29C	2.7	21.0	9.2	1585.	39.4	1624.4	2418.	60.	2478.	" "
31A	5.5	44.0	4.2	2104.	30.5	2134.5	2254.	32.7	2286.7	Max contin load
31B	5.5	44.0	4.15	2167.	0	2167.	2315.	0	2315.	" " "
31C	5.5	44.0	4.1	2213.	15.3	2228.3	2357.	16.3	2373.3	" " "
33A	3.8	30.0	7.7	1594.	28.6	1622.6	2157.	38.7	2195.7	High load, norm O_2
33B	3.8	30.0	8.15	1502.	28.4	1530.4	2104.	39.7	2143.7	" " " "
33C	3.8	30.0	8.15	1538.	31.2	1569.2	2154.	43.7	2197.7	" " " "

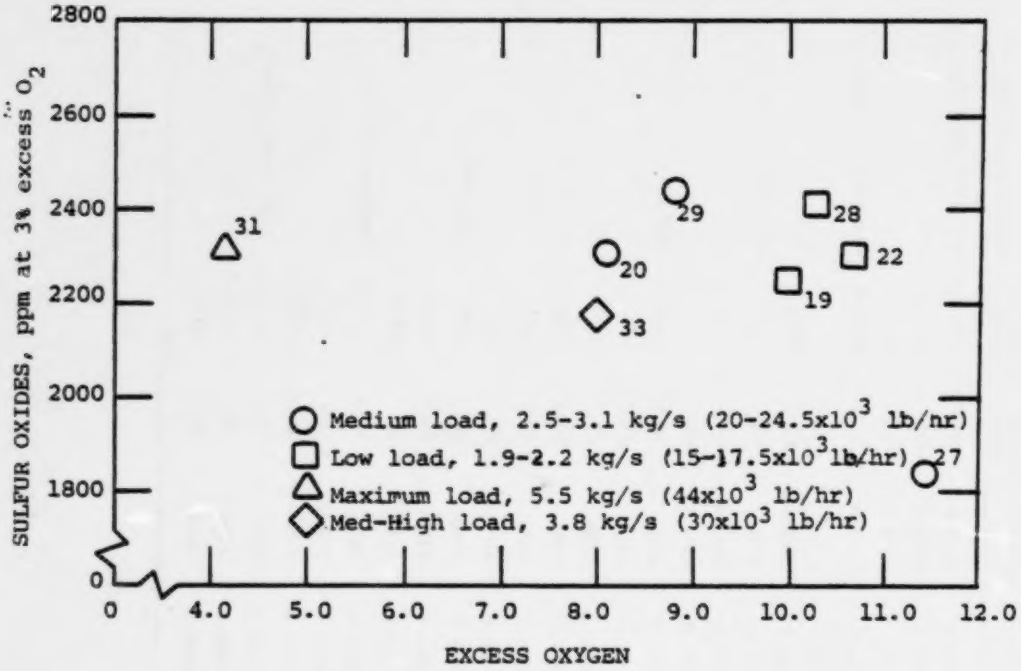


Figure 5.3-5. Excess oxygen vs. sulfur oxide emissions at various loads, Stout Boiler 2, West Kentucky coal.

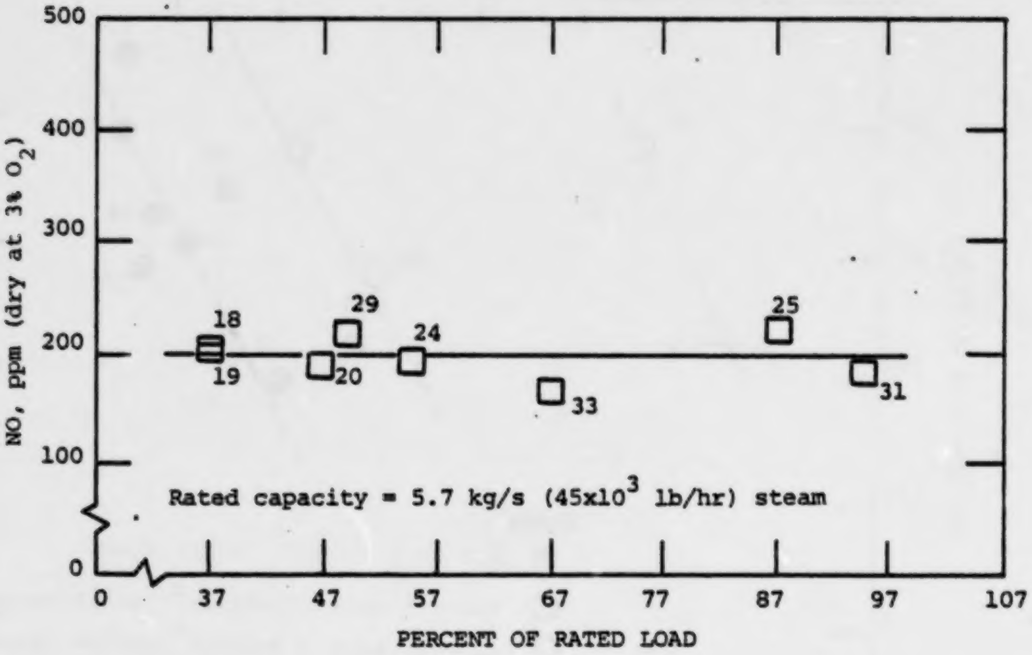


Figure 5.3-6. Load vs. NO emissions, as-found operation, Stout Boiler 2. West Kentucky coal.

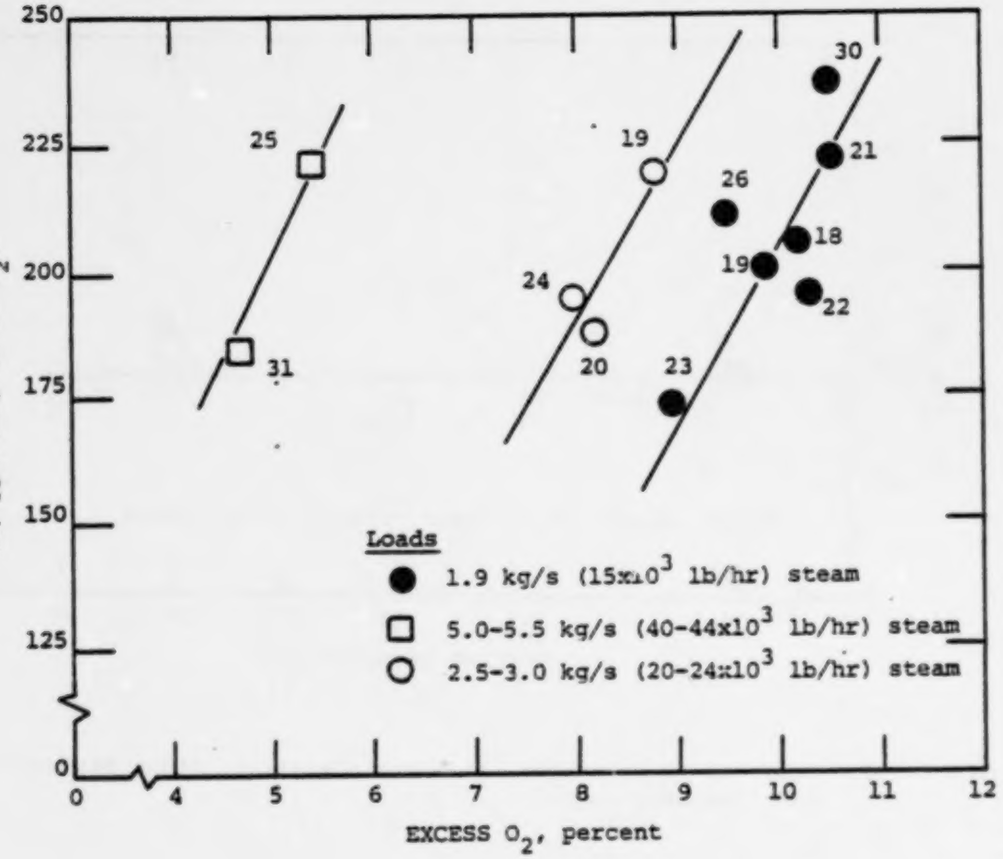


Figure 5.3-7. NO emissions vs. excess O_2 at various loads, Stout Boiler 2, West Kentucky coal.

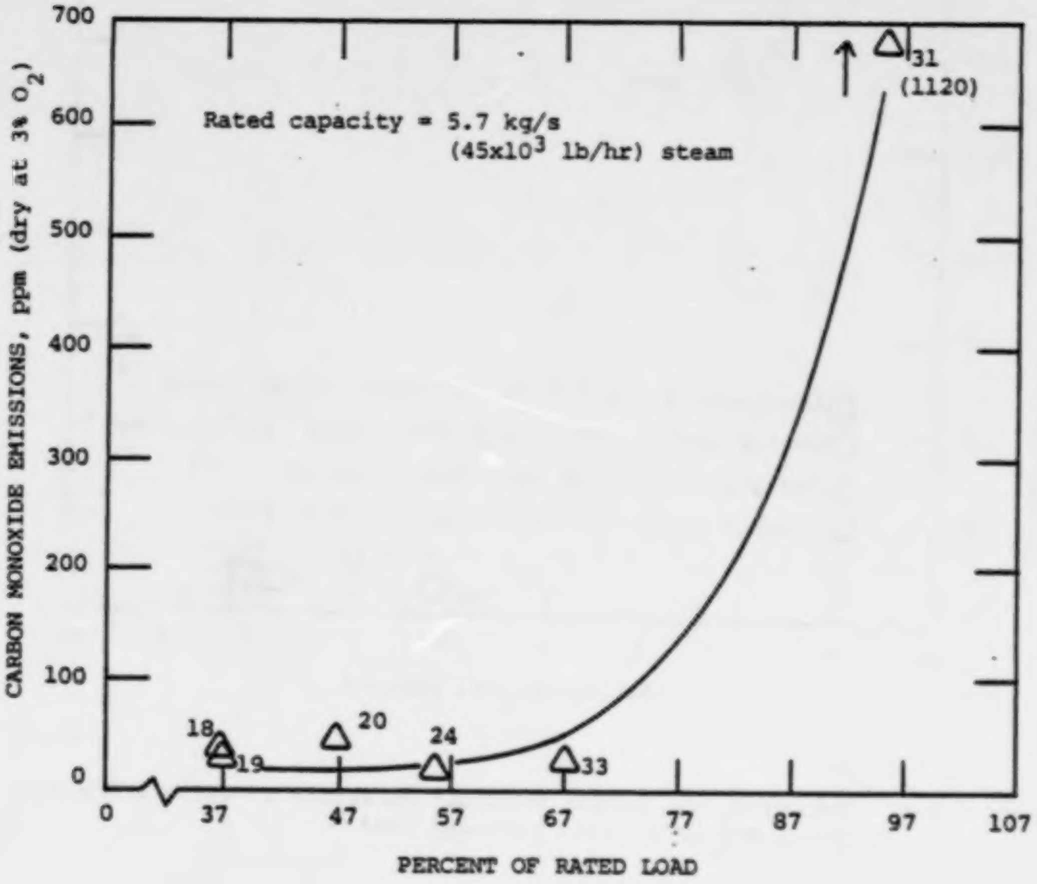


Figure 5.3-8. Load vs. carbon monoxide emissions at as-found operation, Stout Boiler 2, West Kentucky coal.

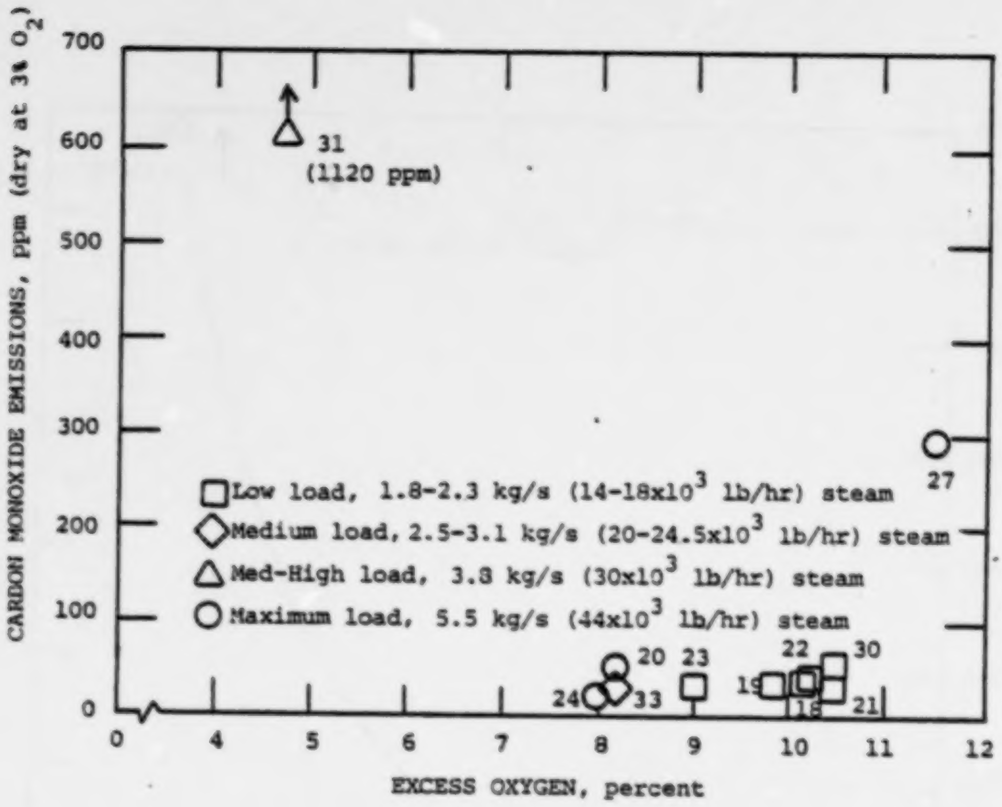


Figure 5.3-9. Excess O_2 vs. carbon monoxide emissions at various loads, Stout Boiler 2, West Kentucky coal.

Figure 5.3-10 presents the particulate emission data versus boiler load in the as-found operating mode. Dust loading shows a trend of increasing particulates with increasing boiler load. The highest emissions recorded were at the maximum load of 5.5 kg/s (44,000 lb/hr) and were 474 ng/J (0.986 lb/MBtu). Figure 5.3-11 presents the particulate emissions versus excess oxygen at a low load of 1.9 kg/s (15,000 lb/hr) steam flow. The dust loading seems to increase slightly with increasing excess air; but, the trend is not pronounced. Increasing air flow could blow additional material off the grate accounting for the increased emissions with increasing oxygen.

Hydrocarbon data revealed slight emissions of hydrocarbons at all loads and excess O_2 levels. Generally, hydrocarbon emissions were less than 40 ppm at all points tested.

5.3.6 Western Coal Burning on Vibragrate Stoker

A. Stoker Operation--

Minor but definite changes must be made on vibrating grate type stokers in order to burn western coals. Three distinct problems exist when attempting to fire western coal on this type of stoker. First, coal ignition is not as rapid. The western coal fire has a tendency to "walk away" from the ignition arch. This problem was remedied by opening up the first air zone control damper and allowing extra air to penetrate the inlet zone of the stoker. Reducing the speed of the grate also helped keep the fire ignited and under the arch.

The second problem with western coal firing is the formation of "blow holes". These bare areas of grate occur when the insulating ash layer is blown off the grate and exposes the metal to the heat of the furnace. This condition was remedied by increasing the normal fuel bed thickness 25% to 38% from about 10.2 cm (4.0 inches) to 15.2 cm (5 inches). This increased the resistance to the air flow from the undergrate air.

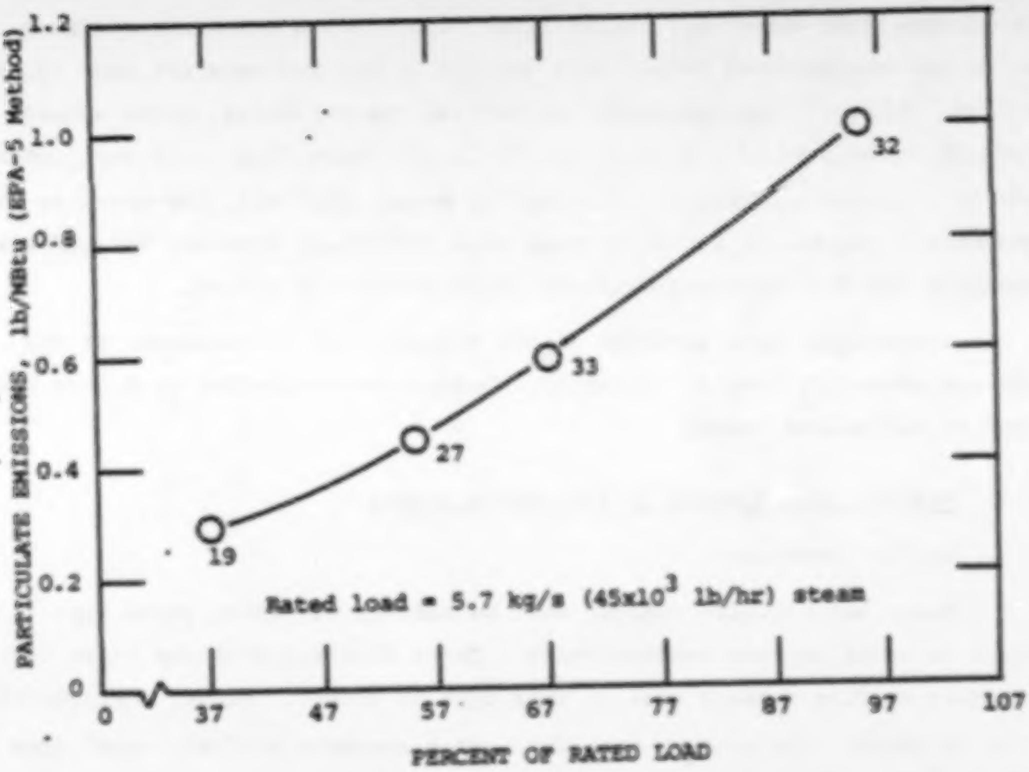


Figure 5.3-10. Particulate emissions vs. percent of rated load, as-found operation, Stout Boiler 2, West Kentucky coal.

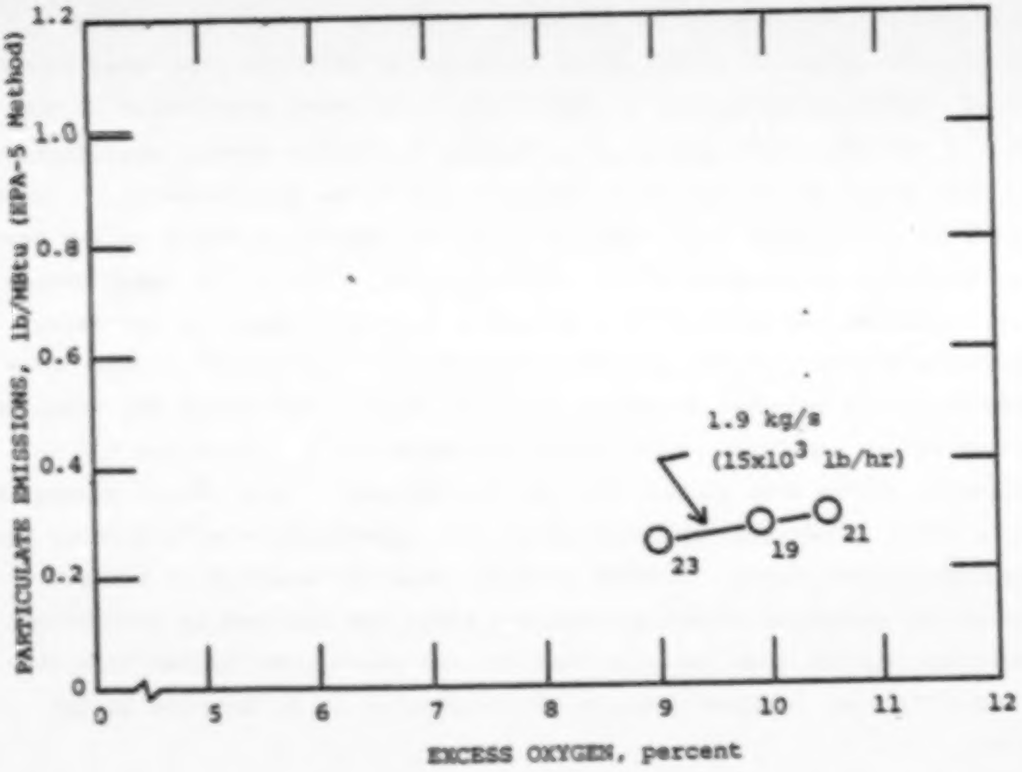


Figure 5.3-11. Particulates vs. excess oxygen, Stout Boiler 2, West Kentucky coal.

A third problem the vibragrate stoker exhibited was an interesting phenomenon with respect to CO emissions. Every time the grate would shake the agitation of the fuel bed would release a large amount of volatiles at once which caused the CO emissions to increase rapidly or "spike" from their relatively low levels to values often in excess of 2000 ppm (the upper range of the CO recording instrument). This behavior is shown graphically on the section of recorder chart presented in Figure 5.3-12 for Wyoming coal firing. This figure shows the steady state emission record for test number 3. Note the spike in CO emission that corresponds to the cyclic vibration of the grate. Another possible explanation of the high CO spikes could be the rapid evolution of volatiles and moisture followed by a quenching effect of the water vapor on the volatile combustion could explain the observed CO spikes. This phenomenon mainly occurred at medium and high loads. Decreasing the vibration frequency and/or amplitude would lessen bed agitation and allow the H_2O and volatiles to evolve more slowly from the Wyoming coal. Also an air preheater could be added to increase the combustion air temperature to help burn up the CO and improve efficiency. A third possible solution would be to promote mixing of the distilled volatiles with air above the fuel bed by increasing the overfire air jet momentum such that the air penetrates further over the fuel bed. This may require redesign of the nozzles or an increase in fan capacity.

When the CO spikes occurred, the furnace pressure would increase. As the load was increased there was less negative draft available from the chimney. When the rapid release of volatiles and moisture occurred, the furnace pressure sometimes went positive. This would cause sparks and smoke to emit from cracks in the breeching. This could be a problem at very high loads.

Ash removal was not a problem with western coal nor was storage of the coal. The western coal did not clinker and, once ignited, burned well. The coal was free burning and individual coal pieces tended to retain their identify throughout the combustion process. That is, they did not swell up in size or stick to other adjacent pieces of fuel. Storage in the underground bunker was no problem. The fuel had been oil treated and even though it contained 40% fines they stuck to the larger pieces of coal and did not become a problem in either storage or conveying.

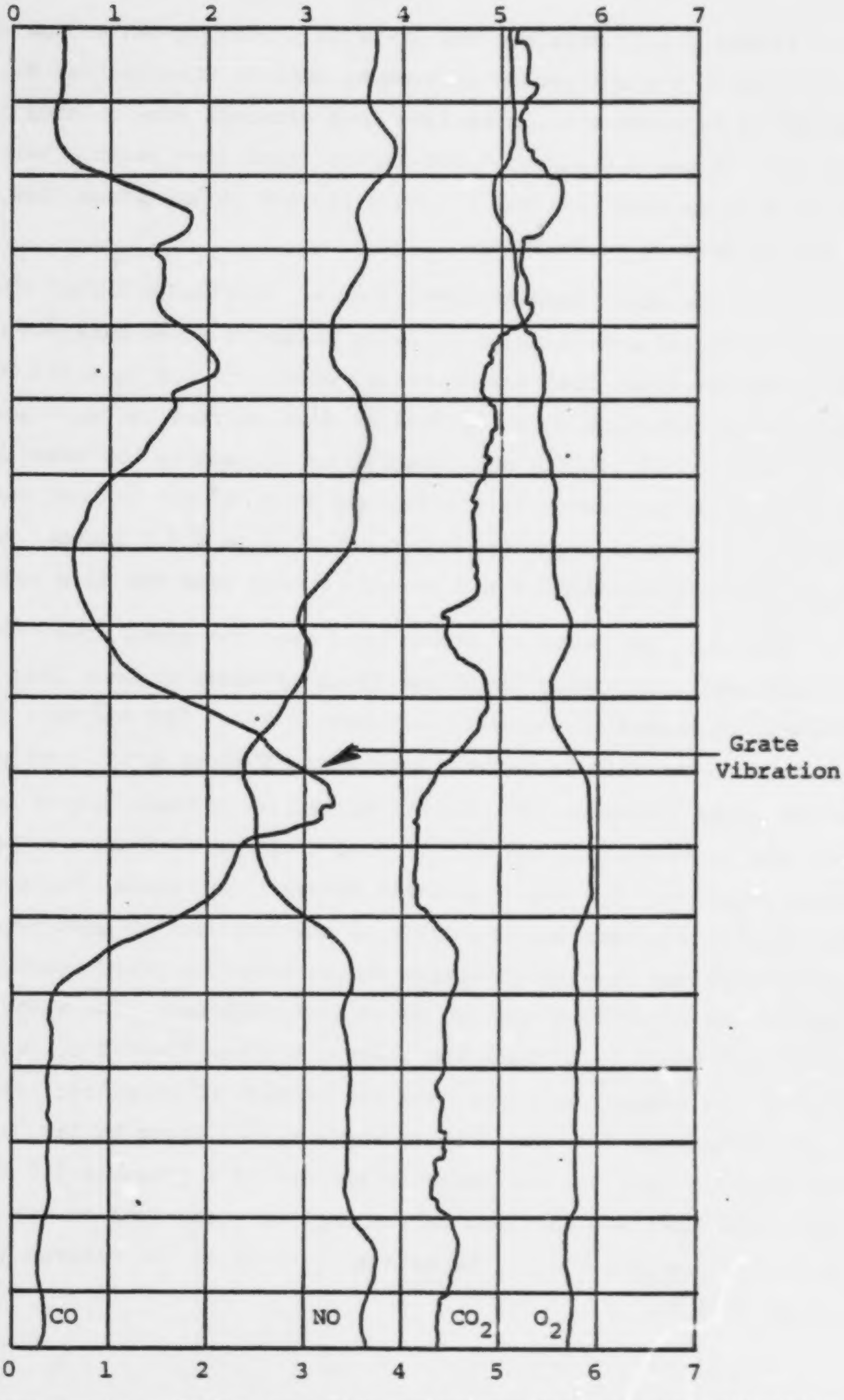


Figure 5.3-12. Carbon monoxide emissions during grate vibration, Stout Boiler 2, Wyoming coal.

B. Exhaust Gas Emissions from Western Coal Firing--

Figure 5.3-13 presents the as-found excess oxygen versus unit load characteristics for combustion of Wyoming coal in Stout Boiler #2. Excess O_2 tended to decrease with increasing load although some scatter is present in the data at the 3.8 kg/s (30,000 lb/hr) steam load point. Maximum load achievable on Wyoming coal was 4.2 kg/s (33,000 lb/hr) steam flow. Maximum load was determined as follows:

Unit was stabilized at 1.9-2.1 kg/s (15-17,000 lb/hr) steam flow. The load was increased artificially by using steam to drive fans and ash conveyor system. Boiler steam load was increased slowly to 4.2 kg/s (33,000 lb/hr). At this point, ignition began to fail as fire started to "walk away" from the furnace arch. This problem was remedied by increasing the overfire air from 8.89 cm (3.5 inches) water at the top, and 20.3 cm (8.0 inches) water at the bottom, to 12.95 cm (5.1 inches) water, and 25.4 cm (10.0 inches) water respectively. The higher overfire air seemed to help keep the fire under the arch.

The fuel bed began to stretch out over the grate area once ignition was stabilized. Initially the flame front extended to zone four, but soon increased its length to midway into zone five. The 4.2 kg/s (33,000 lb/hr) load apparently is maximum load since furnace draft goes positive each time the grate vibrates. The boiler outlet (or uptake) damper is wide open (100%) and no additional natural induced draft is available to keep the furnace negative. The air is lowered somewhat to reduce furnace draft. A point is reached where furnace draft is staying more or less negative with slight excursions into the positive regime when the grate vibrates. CO emissions are relatively high at about 1200-1800 ppm. The stack emits a dark puff of smoke with each grate vibration. A steam flow of 4.2 kg/s (33,000 lb/hr) is the maximum reliable load due to high CO emissions, visible smoke and low furnace draft. Hence, with western coal Stout Boiler #2 was able to operate at 4.2 kg/s (33,000 lb/hr) steam out of a possible 5.5 kg/s (44,000 lb/hr) steam that was obtained on the West Kentucky fuel or 75% of the boiler potential on eastern coal. The excess O_2 level at the maximum load was found to be 4.5%.

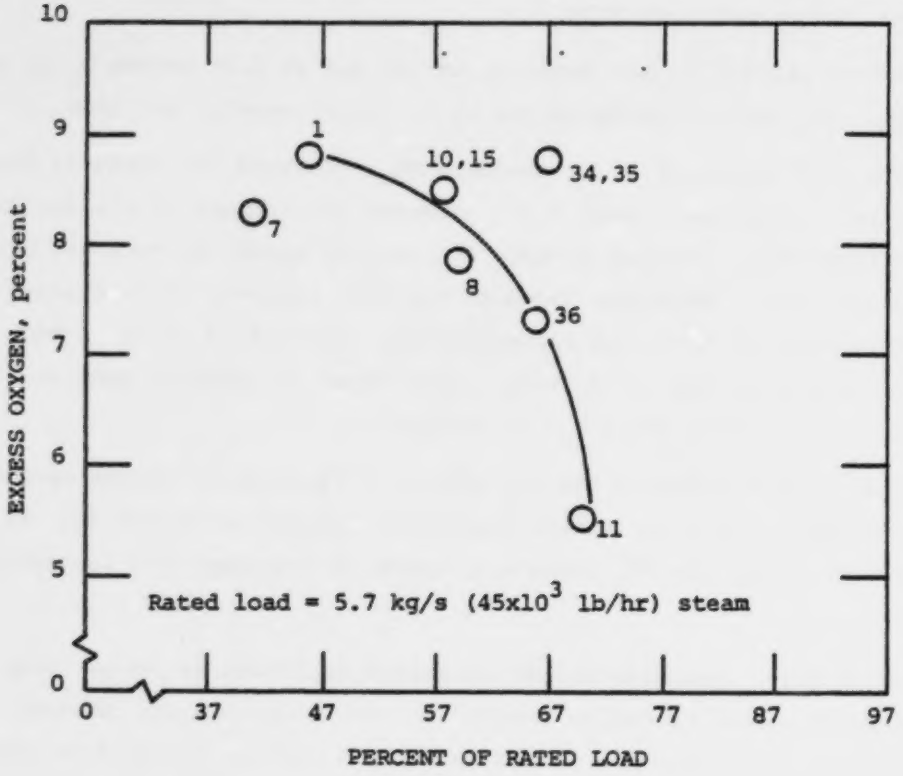


Figure 5.3-13. Load vs. excess oxygen, as-found operation, Stout Boiler 2, Wyoming coal.

Sulfur oxide emissions were obtained at the maximum load for western coal and were found to be 485 ppm at 3.0% excess O_2. The SO_3 component of total sulfur oxides was about 5.0%.

Nitrogen oxide (NO) was found to be 160 ppm at 3.0% excess O_2 at the maximum load. NO_x was not measured due to an out-of-service hot line.

Figure 5.3-14 presents the as-found SO_x emissions for Stout #2 versus load for normal operation. Table 5.3-4 presents the summary of all SOx data taken on Wyoming coal. Overall average SO_x at 3.0% excess O_2 were 616 ppm for the western coal. Emissions based on the fuel analysis of an average fuel sulfur content of 0.83% and higher heating value of 23 MJ/kg (∿9900 Btu/lb) would yield 763 ppm at 3.0% O_2. This seems to indicate some sulfur retention by the ash when western coal is fired.

Figure 5.3-15 presents the SO_x data as a function of excess oxygen. SOx emissions appear constant at low loads with changes in excess O_2. At high and medium loads, the SO_x emissions appear to increase with increasing excess air.

Figure 5.3-16 presents the NO emissions for Stout #2 versus load for the as-found normal operation condition. The emissions are constant with increasing load. The average value of measured NO is 164 ppm at 3.0% excess oxygen in the as-found condition. Figure 5.3-17 presents the variation of NO emissions with excess oxygen level at low and medium loads. NO formation show a definite trend of increasing emissions with increasing oxygen levels.

Figure 5.3-18 presents the carbon monoxide emissions over the Stout #2 load range in the as found condition CO emissions were generally low (less than 160 ppm) except for the maximum load point of 4.2 kg/s (33,000 lb/hr) steam flow. Figure 5.3-19 presents CO emissions as a function of excess O_2 levels at low and medium loads. Except for the high CO level at maximum load most CO emissions were low. The CO emissions did spike to high levels when the grate shook at loads of medium size and up. The data shown in Figure 5.3-19 does not present the spiking values.

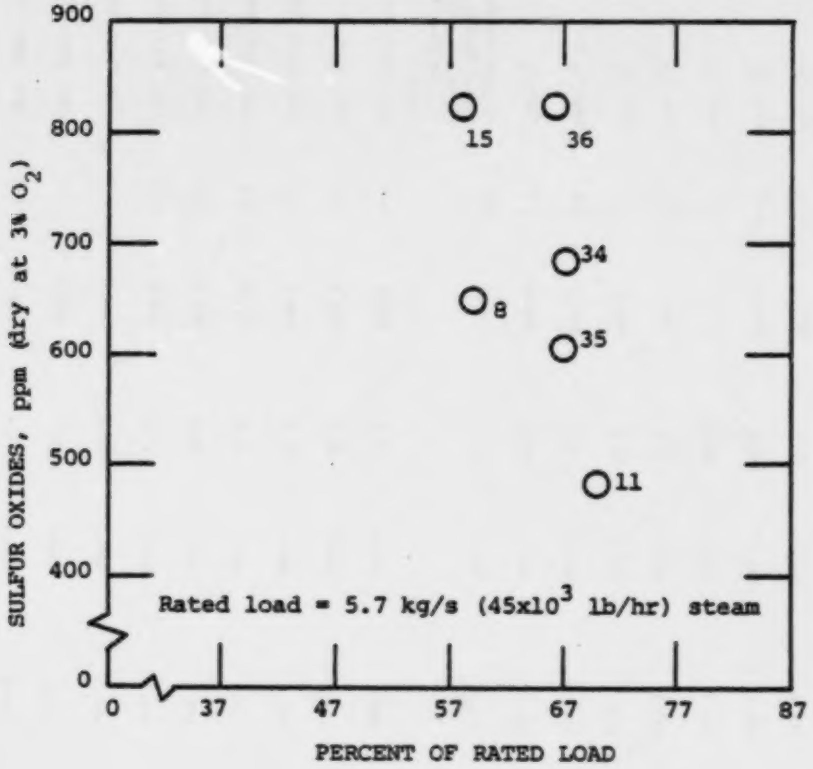


Figure 5.3-14. Load vs. sulfur oxide emissions, as-found operation, Stout Boiler 2, Wyoming coal.

TABLE 5.3-4. SULFUR OXIDES EMISSIONS SUMMARY, UNIVERSITY OF WISCONSIN, STOUT BOILER #2, WYOMING COAL

Test No.	kg/s (10^3 lb/hr) Steam Load	O_2 (%)	SO_2 (uncorr ppm)	SO_3 (uncorr ppm)	SOx (uncorr ppm)	SO_2 (corr ppm)	SO_3 (corr ppm)	SOx (corr ppm)	Percent SO_3/SOx	Test Description
2A	2.7 (21.5)	7.7	391.7	24.2	415.9	530	32.8	562.8	5.8	
2B	2.7 (21.5)	7.7	457.5	17.4	474.9	619.2	23.5	642.7	3.6	Nom. O_2
2C	2.7 (21.5)	7.6	559.4	14.2	573.6	751.4	19.1	770.5	2.5	Nom. O_2
3A	2.3 (18)	6.2	371.6	20.7	392.3	451.9	25.2	477.1	5.3	Nom. O_2
3B	2.3 (18)	6.2	383.0	27.2	410.2	465.0	33.1	398.9	6.6	Nom. O_2
3C	2.3 (18)	6.2	367.0	27.8	394.8	446.3	33.8	480.1	7.0	Nom. O_2
4A	2.1 (17)	9.1	352.7	18.4	371.1	533.5	27.8	561.3	4.9	High O_2
4B	2.1 (17)	9.9	281.2	20.1	301.3	456	32.6	488.6	6.7	High O_2
4C*	2.1 (17)	10.0	204.3	19.4	223.7	334.3	31.7	366.0	8.7	*A leak was found in system during sampling @ 0.4 CF. Duration of leak is unknown
8A	3.5 (27.5)	7.3	569.3	28.3	597.6	748.0	37.2	785.2	4.7	Med. load, Nom. O_2
8B	3.5 (27.5)	7.3	448.5	31.0	479.5	589.3	40.7	630.0	6.5	Med. load, Nom. O_2
8C	3.5 (27.5)	7.3	384.2	22.2	406.4	504.8	29.2	534.0	5.5	Med. load, Nom. O_2
11A	4.2 (33)	3.75	478	29.7	497.7	498.8	30.9	529.7	5.1	Max. load, Nom. O_2
11B	4.2 (33)	3.75	435.8	17.2	453.0	454.7	17.9	472.6	3.6	Max. load, Nom. O_2
11C	4.2 (33)	3.75	409.4	24.8	434.2	427.2	25.5	453.1	5.5	Max. load, Nom. O_2
13A	3.2 (25.5)	6.0	439.1	16.8	455.9	526.9	20.2	547.1	3.7	Med. load, Low O_2
13B	3.2 (25.5)	6.0	399.5	12.9	412.4	479.4	15.5	494.9	3.1	Med. load, Low O_2
13C	3.2 (25.5)	6.0	392.3	23.7	416.0	470.8	28.4	499.2	5.7	Med. load, Low O_2

(continued)

TABLE 5.3-4 (continued).

Test No.	kg/s (10^3 lb/hr) Steam Load	O_2 (%)	SO_2 (uncorr ppm)	SO_3 (uncorr ppm)	SOx (uncorr ppm)	SO_2 (corr ppm)	SO_3 (corr ppm)	SOx (corr ppm)	Percent SO_3/SOx	Test Description
14A	3.2 (25)	9.9	554	20.7	574.7	898	33.6	931.6	*	Med. load, High O_2 (* May be in error)
14B	3.2 (25)	8.25	462.7	15.4	478.1	653.2	21.2	674.4		Med. load, High O_2
14C	3.2 (25)	8.5	474.1	12.2	486.3	682.7	17.6	700.3		Med. load, High O_2
15A	4.5 (35.5)	7.0	649.3	9.27	658.6	834.8	11.9	846.7		Med. load, Nom. O_2
15B	4.5 (35.5)	7.0	662.3	13.9	676.2	800.1	17.9	818.0		Med. load, Nom. O_2
15C	4.5 (35.5)	7.0	634.9	14.0	648.9	816.3	18.0	834.3		Med. load, Nom. O_2
16A	2.0 (15.5)	7.4	364	11.2	375.2	481.8	14.8	496.6		Low load, Nom. O_2
16B	2.0 (15.5)	7.5	317.3	15.4	332.7	423.0	20.5	443.5		Low load, Nom. O_2
16C	2.0 (15.5)	7.5	350.6	14.6	365.2	467.4	19.5	486.9		Low load, Nom. O_2
35A	3.8 (30.0)	7.9	419	16.0	435.0	575	22.0	597		High load, Norm. O_2
35B	3.8 (30.0)	8.2	420	11.6	431.6	591	16.3	607.3		High load, Norm. O_2
35C	3.8 (30.0)	--	425	10.7	435.7	598	15.0	613.0		High load, Norm. O_2
36A	3.7 (29.5)	6.7	833	7.0	840.0	1049	9.0	1058.0		High load, Norm. O_2
36B	3.7 (29.5)	5.8	645	14.0	659.0	764	16.6	780.6		High load, Norm. O_2
36C	3.7 (29.5)	6.5	535	7.5	542.5	664	9.3	673.3		High load, Norm. O_2

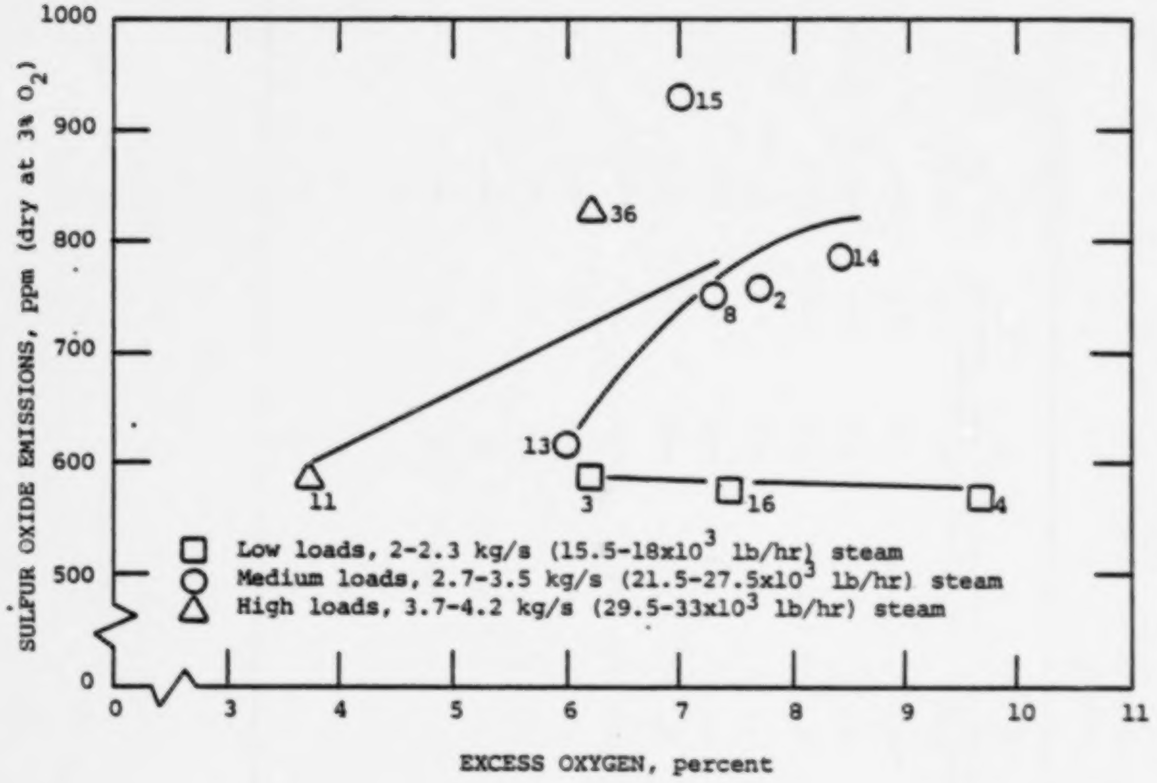


Figure 5.3-15. Excess oxygen vs. sulfur oxide emissions at various loads, Stout Boiler 2, Wyoming coal.

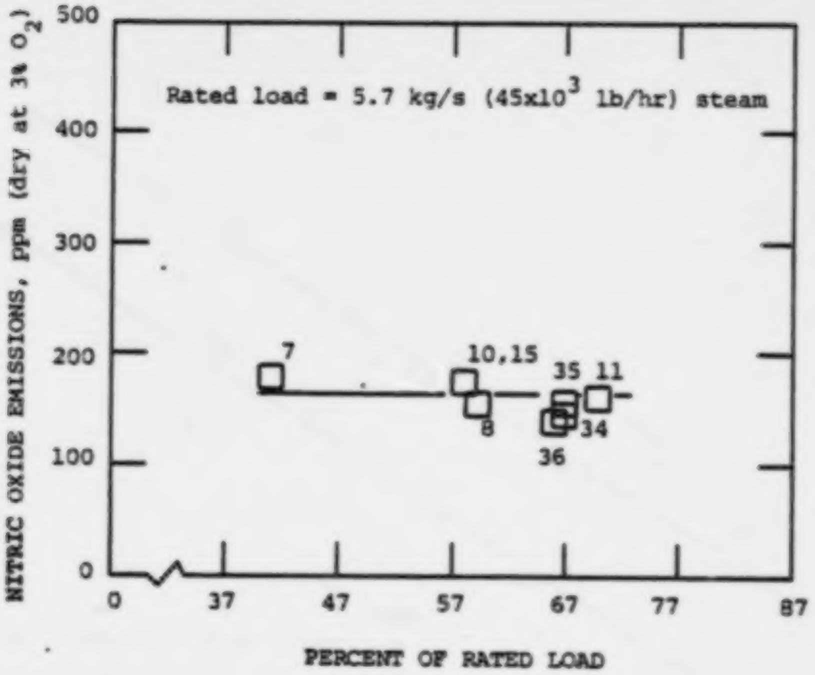


Figure 5.3-16. Load vs. NO emissions, as-found operation, Stout Boiler 2, Wyoming coal.

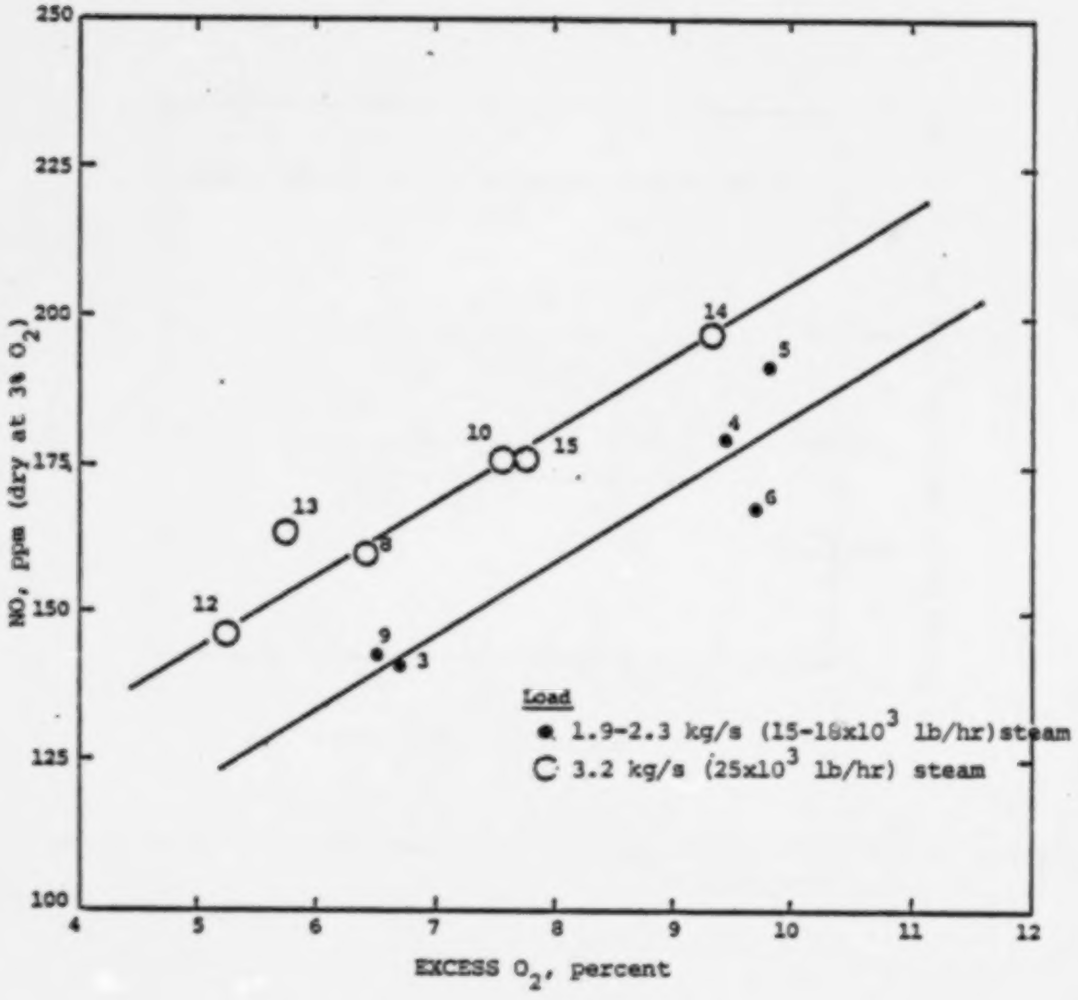


Figure 5.3-17. Excess oxygen vs. NO emissions, Stout Boiler 2, Wyoming coal.

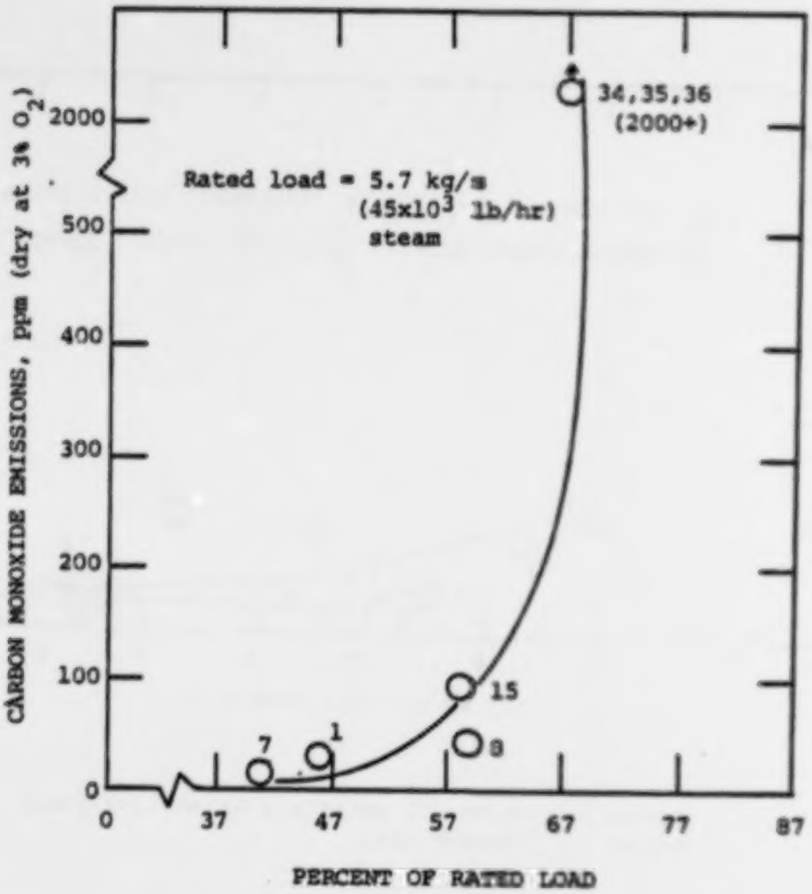


Figure 5.3-18. Load vs. CO emissions, as-found operation, Stout Boiler 2, Wyoming coal.

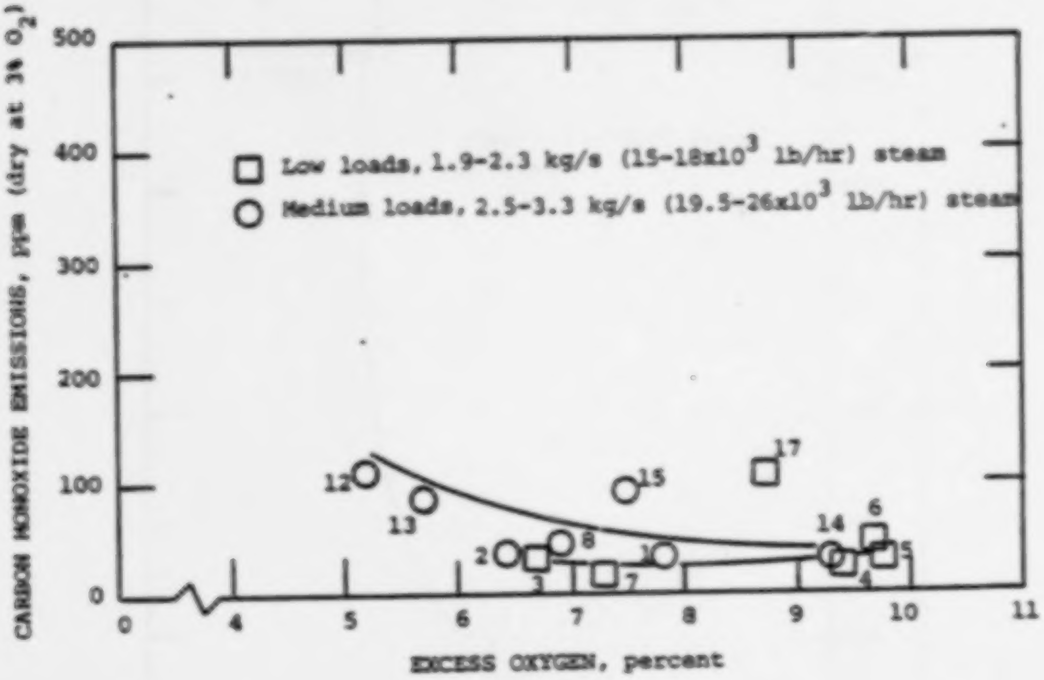


Figure 5.3-19. Excess oxygen vs. CO emissions at various loads, Stout Boiler 2, Wyoming coal.

Figure 5.3-20 presents the particulate emissions versus boiler load in the as-found operating mode. Dust loading shows a trend of increasing particulates with increasing boiler load. The highest emissions recorded were at 3.8 kg/s (30,000 lb/hr) steam flow and were found to be 625.2 ng/J (1.454 lb/MBtu). Figure 5.3-21 presents the particulate emissions versus excess O_2 at loads of about 2.1 and 3.2 kg/s (17,000 and 25,500 lb/hr) steam. These two curves show an interesting rise at both high and low excess air levels. The increased particulates at high excess air levels would indicate extra mass blown off the grate by the higher air flows. The increased particulates at low excess oxygen may be due to incomplete combustion of the carbon particles.

Limited hydrocarbon data was obtained due to a faulty hydrocarbon analyzer. However, emissions that were obtained showed emissions to be low and less than 50 ppm.

5.3.7 Comparison of Eastern Versus Western Coal Burning on a Vibrating Grate Stoker

The stoker being considered is of the vibrating grate configuration with a nameplate capacity of 5.7 kg/s (45,000 lb/hr) steam flow. Actual continuous capacity tests found that the maximum continuous load obtainable while firing a West Kentucky coal of about 28.6 MJ/kg (12,300 Btu/lb) heating value was 5.5 kg/s (44,000 lb/hr) steam flow. Under similar defining conditions the Wyoming coal could only obtain 75% of that figure or had a maximum continuous capacity of 4.2 kg/s (33,000 lb/hr) steam flow.

This type of stoker was designed and built to fire an eastern type fuel but it can successfully fire a western type fuel with certain definite changes in operating procedures. First, one must increase the fuel bed thickness 25-38%. Normal bed thickness for West Kentucky coal was approximately four inches. When firing Wyoming coal this had to be increased to 12.7-13.97 cm (5 to 5-1/2 inches). The increased fuel bed thickness deterred formation of blow holes in the fuel bed by increasing its resistance to undergrate air flow. This also helped protect the grate since less ash is present when firing western coals. Ignition is a problem with Wyoming

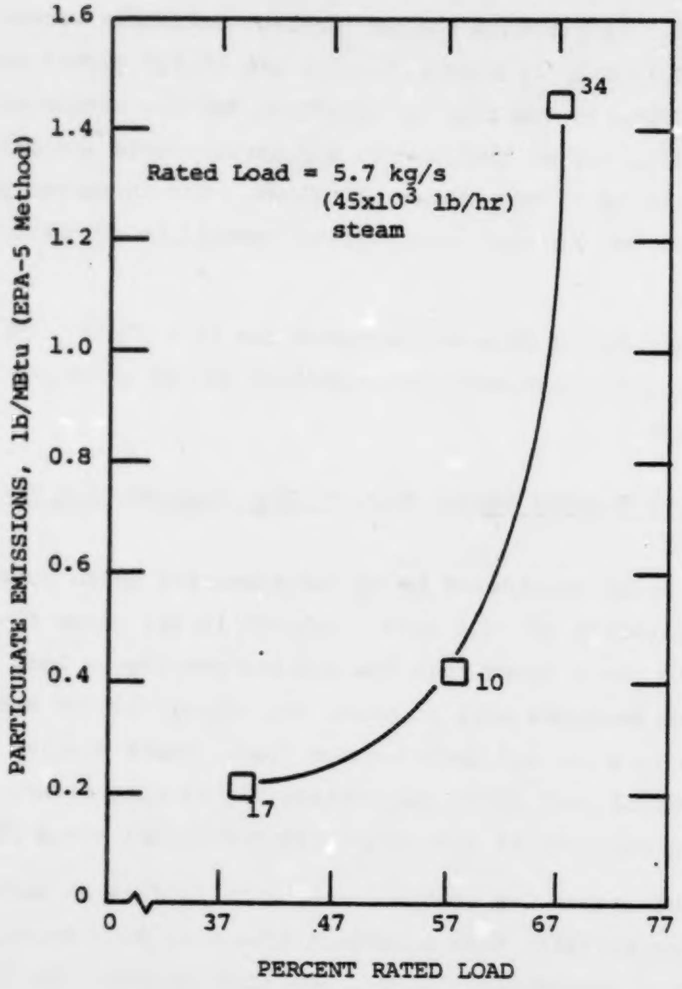


Figure 5.3-20. Particulates vs. load, as-found operation, Stout Boiler 2, Wyoming coal.

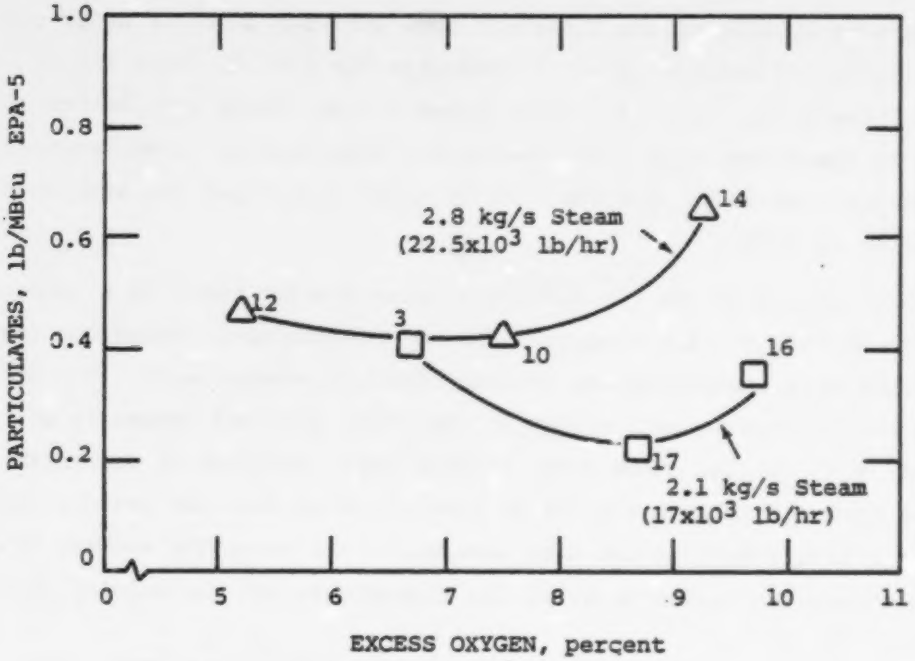


Figure 5.3-21. Particulates vs. excess oxygen, Stout Boiler 2, Wyoming coal.

coal. Heat required to raise the fuel to ignition temperature is lost to distilling off the high moisture content of the western coal. This problem is overcome by opening up the first air zone (the one directly under the ignition arch) and permitting air to mix with the fuel to start firing earlier in the arch. Also, the grate speed can be slowed somewhat to allow the fuel to spend more time under the arch. Additionally, some increase in overfire air seems to keep the fire "pushed" back under the arch when Wyoming coal is fired.

When looking at the two different coals burning there is a noticeable difference in firing under the arch. On the eastern coal combustion the fire is much more pronounced and defined than the western coal. The West Kentucky coal seemed to burn closer to the inlet gate and deeper in or under the arch. On the other hand, Wyoming coal, although it does burn under the arch and maintains ignition once you slow down the grate a little, does burn a little farther out from underneath the arch. The eastern coal also had a darker orangish color to its flames than did the western coal.

Air dampers had to be changed when burning Wyoming coal. For eastern coal firing,the predominant air passages were zones two and three, especially zone two. Zone one,by the way,is always closed when firing eastern coal. For Wyoming coal combustion the first zone is opened up a little, the second zone is pinched back and the third zone is opened some more.

Another problem initially associated with western coal firing was fines sifting through the grate. This was only a problem during initial start-up before an ash bed could be established over the grate area. However, when the fines sifted through the grate they would land on the top of the air zone dampers and ignite forming metal-warping fires on the dampers. Once this problem was discovered, the solution was found to be a quick series of snapping open and shut of the dampers periodically during start-up to purge the tops of the dampers of the fine siftings. Once a fuel bed was established this action was no longer necessary.

There were no problems concerning piling and storage of the western coal. It conveyed well in the conveyor, stored well and worked fine in the coal elevator. The batch of western coal tested appeared to have a considerable amount of fines in it, perhaps 40% or more. However, this coal had been oil-treated and there was no problem with fugitive dust.

From time to time some segregation was noted in the coal hopper. Fines seemed to congregate in certain areas. There didn't appear to be any pattern for this and the segregation sometimes resulted in an unevenly distributed fuel bed with the fines being more closely packed and more restrictive to air flow.

Another observation of the differences in the two fuels was the free burning characteristic of the Wyoming coal. As the western coal burned, each piece would retain its individual identity and original size more or less. On the other hand, the eastern coal would coke and then swell up in size to two or three times its original size. During this swelling process adjacent pieces of eastern coke would tend to stick to one another and form a non-porous air-resistive area. This, of course, is one reason more air was required in the later air zones in the stoker when firing eastern coal.

There seemed to be more "sparklers" or air-borne incandescent particles associated with the Wyoming coal firing. Also, extreme changes in furnace pressure would accompany the shaking of the grate. This grate agitation would release large quantities of volatiles which would combust quickly and increase the relative volume in the furnace quite rapidly. This was especially noticeable at medium to high loads and at high excess air levels. Also, there were more sparklers with the Wyoming coal particularly when the grate shook. When that happened, you could see them fly out from the fuel bed in large numbers. This was not so apparent for eastern coal combustion.

There seemed to be some slag formations on the water tubes that made up the ignition arch when western coal was burned. This was not as prevalent on the eastern coal.

Another phenomenon that western coal exhibited when the grate shook, besides an increase in furnace pressure, was large increases in carbon monoxide emissions. The nominal steady state levels of CO were generally less than 50 ppm but would take a sharp spike upward and go off the scale of the mobile lab's 0-2000 ppm CO analyzer's high range.

There were no problems at all with clinker formation while burning Wyoming coal. As a matter of fact, there was only one day when a clinker started to form and that was a day when there was quite a few fines in the hopper and segregation was severe. On eastern coal, however, there were three or four days when clinkers were formed and some were quite large. One in particular almost covered the entire grate area and took quite some time and effort to remove.

Overfire air was used and is used for both western and eastern coal firing. The overfire air did not seem to make any improvement in the CO spikes mentioned above during western coal firing but did seem to help keep the western coal flame-front under the ignition arch.

There were some interesting differences in emission characteristics between the western and eastern coal firing. The excess oxygen requirement was slightly reduced for western coal firing. Sulfur oxides were significantly lower on the Wyoming coal at 616 ppm at 3.0% O_2 versus 2265 ppm at 3.0% O_2 for the West Kentucky fuel. This represents a 72.8% reduction in emissions. Emissions based on the fuel analysis showed western coal to be 763 ppm at 3.0% O_2 and Eastern coal to be 2110 ppm at 3.0% O_2 or only a 64% reduction. The additional loss in sulfur oxides may be due to some sulfur retention characteristic of western coal ash.

NO emissions were slightly lower on the Wyoming coal. Western coal NO averaged 164 ppm at 3.0% excess oxygen versus an average of 185 ppm at 3.0% excess oxygen for the eastern fuel.

Both fuels had low overall CO emissions during normal operation except at maximum load. The western coal firing exhibited the interesting phenomenon of spiking to high levels of CO (>2000 ppm) when the grate shook when firing at medium loads and higher. Eastern coal did not exhibit this behavior.

Particulate emissions were lower on western coal at low and medium loads but tended to increase at the higher loads. Hydrocarbon emissions were about the same for both fuels,and very low (<50 ppm).

5.4 UNIVERSITY OF WISCONSIN, EAU CLAIRE

The testing described in this section was done on Boiler #1 of the Central Heating Plant on the University of Wisconsin, Eau Claire campus located in Eau Claire, Wisconsin.

The unit is an overfed traveling grate stoker manufactured by Bros Inc. in 1966. It has a nameplate rating of 7.6 kg/s (60,000 lb/hr) steam flow and is fired with a Laclede traveling grate stoker supplied by the Laclede Stoker Company. Additional data on the unit design and operation are listed below:

- Design Pressure - 1.2 MPa (160 psig)
- Design Temperature - saturated
- Actual Day-to-Day Operating Conditions
  - Operating Pressure - 1.1 MPa (150 psig)
  - Operating Temperature - saturation
- Boiler Heating Surface - 568 m^2 (6,117 sq. ft.)
- Water Wall Heating Surface - 50.4 m^2 (543 sq. ft.)
- Furnace Width - 3.96 m (13'0")
- Furnace Depth - 3.12 m (10'3-1/2")
- Effective Combustion Volume - 78.7 m^3 (2,780 cu. ft.)
- Grate Width - 366 m (12'0")
- Effective Grate Length - 4.6m (14'11")
- Net Effective Grate Area - 16.6 m^2 (179 sq. ft.)
- Grate Zones - 6
- Overfire Air Fan Capacity - 59.5 m^3/min (2,100 CFM)
- Percent of Total Air Supplied by Overfire Air Fan - 10%
- Forced Draft Fan Capacity - 623 m^3/min (22,000 CFM)
- Heat Release - 9.43x10^5 GJ/hr m^3 (25,300 Btu/cu. ft.)

A drawing of the stoker is shown in Figure 5.4-1.

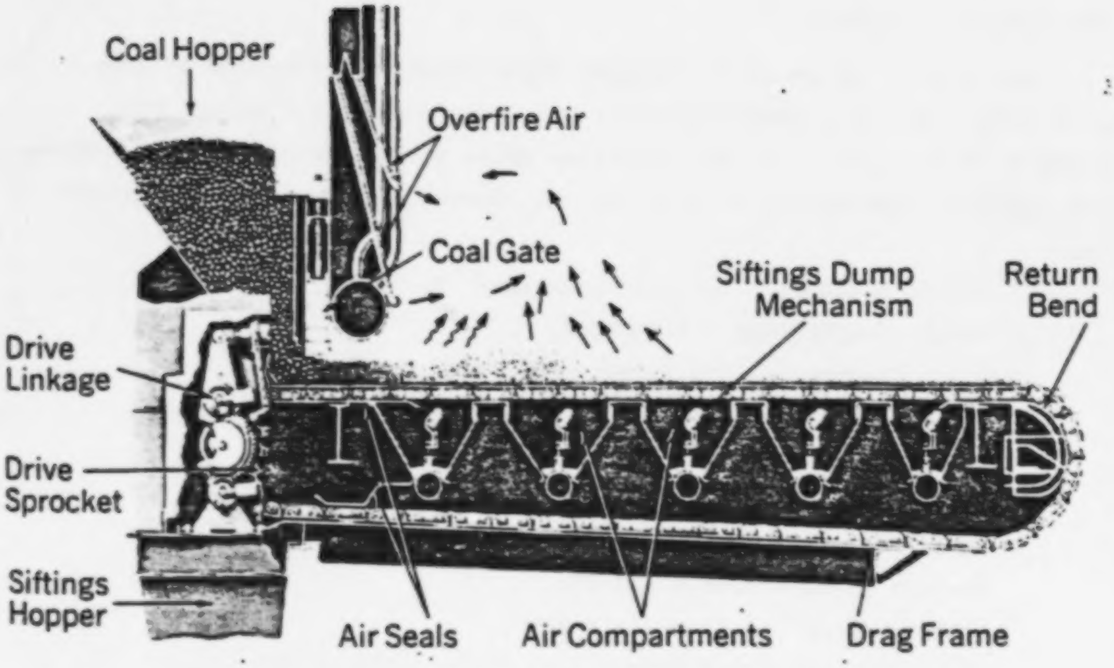

Coal Hopper
Overfire Air
Coal Gate
Siftings Dump Mechanism
Return Bend
Drive Linkage
Drive Sprocket
Siftings Hopper
Air Seals
Air Compartments
Drag Frame

Figure 5.4-1. Chain grate overfeed stoker.

5.4.1 Unit Operation

Coal enters the stoker from above from a hopper which is fed by a conveyor system. The coal then passes through an adjustable coal gate onto the leading edge of the grate. The gate height determines the fuel bed thickness. Fuel feed rate is determined by the forward speed of the traveling grate. The traveling grate is in a horizontal position and travels from the coal hopper towards the ash pit side of the furnace. The grate is not watercooled; therefore, it is important that changes in factors such as fuel bed thickness and distribution, ash quantity and composition, and excess air level be carefully considered or else overheating of grate may occur.

As coal enters the furnace, it is heated to ignition temperature in a short refractory arch section. Unheated combustion air is supplied to the unit by a forced draft fan. Combustion air enters the system from below the grate through individually adjustable air dampers. Local fuel-to-air ratios can be adjusted across the fuel bed as the bed travels slowly toward the ash pit. There are six burner-zone air dampers. Additional overfire air is introduced above the grate surface to complete combustion and prevent smoking. Overfire air is supplied by a separate blower. The furnace is maintained slightly negative by the natural draft created by the smoke stack.

Hot combustion gases from the grate travel upward in the furnace. At the top of the boiler they begin a downward pass through the back section of the boiler and then one more upward passage before exiting the unit. From the unit the gases flow through a horizontal exhaust duct to the base of the stack, then upward and exit to atmosphere.

This unit has no dust collection device per se; however, the exhaust duct is oversized for the boiler and considerable particulates settle out by gravity in the horizontal section of the breaching and bottom of the stack. Siftings from the grate and ash from the ash pit are pneumatically removed from the system.

5.4.2 Sampling Location (Gaseous, Particulates, SOx)

Gaseous, particulates, and SOx samples were taken from the breeching between Unit #1 and the stack. Figure 5.4-2 is a cross section of the breeching showing locations of gaseous probes and particulate traverse points. SO_x samples were taken in either port 2 or 3 using probes which varied in length from 45.7 to 91.44 cm (1.5 to 3.0 feet).

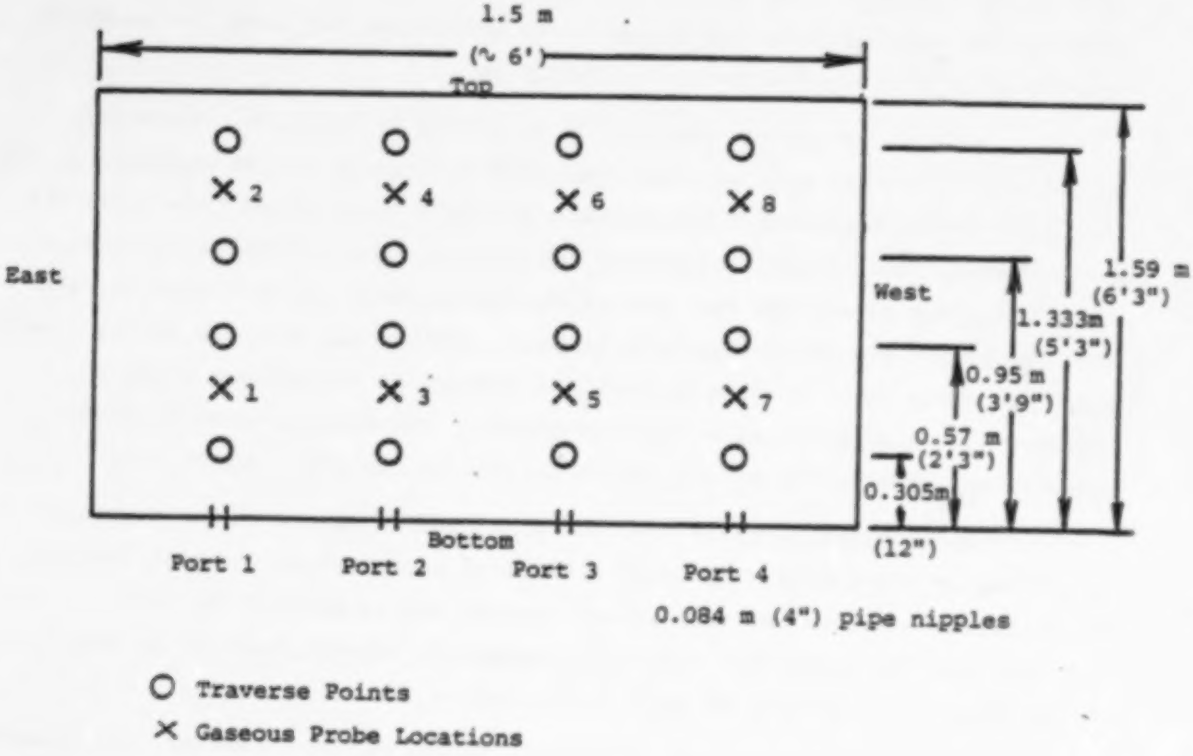

1.5 m
(∿ 6')
Top
East
West
×2
×4
×6
×8
×1
×3
×5
×7
1.59 m
(6'3")
1.333m
(5'3")
0.95 m
(3'9")
0.57 m
(2'3")
0.305m
(12")
Bottom
Port 1
Port 2
Port 3
Port 4
0.084 m (4") pipe nipples
○ Traverse Points
× Gaseous Probe Locations

Figure 5.4-2. Sample port locations in Unit 1 at University of Wisconsin, Eau Claire.

5.4.3 Fuels

The base coal was a West Kentucky coal from the Vogue mine, Seam #11. Proximate and ultimate analyses of fuel samples taken during the testing are presented in Table 5.4-1.

The test coal was from the Bighorn mine in Wyoming. Proximate and ultimate analyses of fuel samples taken during the testing are presented in Table 5.4-2.

TABLE 5.4-1. FUEL ANALYSIS - BASE COAL, WEST KENTUCKY - VOGUE

Proximate Analysis (2 Samples)			Ultimate Analysis (1 Sample)	
Moisture %	7.86;	7.42	Hydrogen %	4.60
Volatiles %	37.09;	38.24	Carbon %	65.05
Fixed Carbon %	48.19;	48.03	Nitrogen %	1.24
Ash %	6.86;	6.31	Oxygen %	9.13
Sulfur %	3.02;	2.80	Chlorine %	0.01
As Received MJ/kg	28.7	28.9	Ash Fusion Temp (H-W)	1292 °K
Btu/lb	12338;	12427		2085 °F
			Moisture %	9.15
			Ash %	8.03
			Sulfur %	2.79

TABLE 5.4-2. FUEL ANALYSIS - TEST COAL, WYOMING, BIGHORN

Proximate Analysis (2 Samples)			Ultimate Analysis (1 Sample)	
Moisture %	21.84;	18.78	Hydrogen %	4.01
Volatiles %	32.41;	34.40	Carbon %	57.98
Fixed Carbon %	40.31	38.60	Nitrogen %	1.10
Ash %	5.44;	8.22	Oxygen %	10.90
Sulfur %	0.62;	0.84	Chlorine %	-0-
As Received MJ/kg	21.9	21.2	Ash Fusion Temp (H-W)	1306 °K
Btu/lb	9429	9123		2110 °F
			Moisture %	20.16
			Ash %	5.13
			Sulfur %	0.72

This unit was part of a heating plant, therefore the maximum load available for the test was a function of the ambient temperature. At the beginning of the testing it was warm and only low loads were available, so all of the low load tests were run first on the western coal and then on the eastern coal. As the weather began to get cooler, testing was resumed on the western coal. The high load tests on western coal were cut short due to operational difficulties in burning the western coal and the unit was switched back to eastern coal for the remainder of the test program. Table 5.4-3 contains a summary of all emissions data taken on Unit 1 at University of Wisconsin, Eau Claire.

5.4.4 Nitric Oxide Emissions - Eastern Coal

For "normal" operating conditions the NO was lowest at low loads 1.9 kg/s ($15x10^3$ lb/hr) steam flow. This may have been due to poor mixing of the fuel and air which caused poor combustion. As the load was increased to the 2.3-3.4 kg/s ($18-27x10^3$ lb/hr) steam flow range the mixing improved causing better combustion which created more NO. At high loads of 5.4-6.2 kg/s ($43-49x10^3$ lb/hr) steam flow, the amount of air available for combustion decreased because a larger percentage of the fuel bed was engaged in active burning than at the lower loads and this resulted in lower NO emissions. Figure 5.4-3 is a plot of NO vs. excess O_2 for eastern coal, with normal operating conditions indicated by test numbers 11, 22, 24, 25, 26, 29, 30, 31, and 33. In every test in which the excess O_2 level was raised there was an increase in NO emissions (tests 12, 19, and 32), and in every test where the excess O_2 level was lowered, there was a decrease in NO emissions (tests 20 and 27).

5.4.5 Nitric Oxide Emissions - Western Coal

For "normal" operating conditions the NO emissions were lowest at the low loads and highest at the high loads. This situation may be misleading because at the high loads the fuel bed was separated into large areas of

TABLE 5.4-3. EMISSION DATA SUMMARY - UNIVERSITY OF WISCONSIN, EAU CLAIRE

Test No.	Date 1975	Load		O_2 percent	CO 3% O_2 (ppm)	CO_2 percent	NO 3% O_2 (dry) (ppm)	Percent Combust.	Particulates		SO_x 3% O_2 (ppm)	SO_x 3% O_2		Fuel S		Sulfur Retention Factor, percent
		kg/s	10^3 lb/hr						ng/J	lb/MBtu		ng/J	lb/MBtu	ng/J	lb/MBtu	
								WESTERN COAL								
1	9/22	3.14	25.0	7.2	250	12.0	135	--	---	--	619	526	1.224	--	---	--
2	9/23	3.14	25.0	7.7	155	11.8	173	29.02	111	0.258	---	---	---	--	---	--
3	9/24	3.78	30.0	7.1	500	12.1	135	26.92	63	0.146	498	423	0.984	--	---	--
4	9/25	3.14	25.0	9.75	145	9.6	178	---	---	---	551	468	1.089	565.5	1.315	82.8
5	9/26	2.28	18.0	10.55	125	9.2	147	29.11	68.4	0.159	---	---	---	--	---	--
6	9/30	1.89	15.0	10.39	48	9.66	151	---	---	---	---	---	---	--	---	--
7	10/1	4.42	35.0	9.8	175	9.8	222	64.9	146.2	0.34	585	497.3	1.156	614.9	1.43	80.8
8	10/2	4.03	32.0	9.7	85	10.3	274	41.04	211.1	0.491	---	---	---	--	---	--
9	10/3	4.42	35.0	10.5	299	9.0	308	40.29	298.9	0.695	---	---	---	--	---	--
10	10/7	4.17	33.0	10.6	371	8.2	275	---	390	0.907	618	525.3	1.222	791.6	1.841	66.4
21	10/29	4.42	35.0	11.1	1143	9.3	302	---	---	---	---	---	---	--	---	--
Average		3.53	28	9.49	300	10.09	209	39.88	184	0.428	574	488	1.135	657	1.53	76.7
								EASTERN COAL								
11	10/9	1.89	15.0	13.2	259	6.9	264	43.95	149.2	0.347	2374	2018	4.693	2105	4.895	95.9
12	10/10	1.89	15.0	15.9	1091	4.7	308	--	---	---	2265	1925	4.477	--	---	--
13	10/13	1.89	15.0	15.1	947	5.2	---	--	---	---	---	---	---	--	---	--
14	10/14	1.89	15.0	15.7	971	4.8	---	--	498.8	1.16	---	---	---	--	---	--
15	10/15	2.39	19.0	11.3	528	8.7	---	--	---	---	2306	1960	4.558	--	---	--
16	10/16	3.35	27.0	11.4	97	8.3	---	--	---	---	2622	2229	5.183	--	---	--
17	10/17	3.14	25.0	11.7	134	8.0	---	38.5	160.4	0.373	---	--	---	--	---	--
18	10/20	2.78	22.0	14.2	663	6.45	---	--	---	---	2072	1761	4.096	--	---	--
19	10/21	2.28	18.0	15.1	886	5.48	340	--	491.5	1.143	---	--	---	--	---	--
20	10/22	2.85	23.0	10.3	73	9.3	253	--	---	---	2517	2139	4.975	1938	4.506	109.4
22	10/30	3.35	27.0	10.9	50	9.1	286	--	---	---	---	--	---	--	---	--
23	10/31	1.89	15.0	16.0	1548	4.8	339	--	---	---	---	--	---	--	---	--
24	11/3	1.89	15.0	13.2	--	7.8	229	--	---	---	---	--	---	--	---	--
25	11/4	1.89	15.0	12.6	383	6.95	203	--	---	---	2343	1992	4.63	--	---	--
26	11/5	1.89	15.0	12.8	547	7.3	236	--	---	---	---	--	---	--	---	--
27	11/10	3.14	25.0	10.1	---	9.5	300	43.57	332	0.772	---	--	---	--	---	--
28	11/11	2.28	18.0	9.8	---	9.1	201	44.44	131	0.305	---	--	---	--	---	--
29	11/12	5.67	45.0	6.6	41	10.9	255	--	---	---	---	--	---	--	---	--
30	11/13	6.17	49.0	6.6	102	11.4	211	35.69	808	1.88	2197	1867	4.34	2053	4.774	90.9
32	11/17	5.42	43.0	8.9	134	9.2	233	--	---	---	---	--	---	--	---	--
33	11/18	1.89	15.0	12.2	84	8.1	199	--	122	0.283	---	--	---	--	---	--
34	11/19	1.89	15.0	13.6	340	6.6	183	--	---	---	2110	1794	4.1709	--	---	--
Average		2.89	32.3	12.1	467	7.66	252	41.23	336.6	0.783	2312	1965	4.569	2032	4.725	98.7
East-West/East, %		+25.6	+25.6	-21.6	-35.0	+31.7	-17	-3.3	-45.3	-45.3	-75.2	-75.2	-75.2	-67.6	-67.6	-22.1

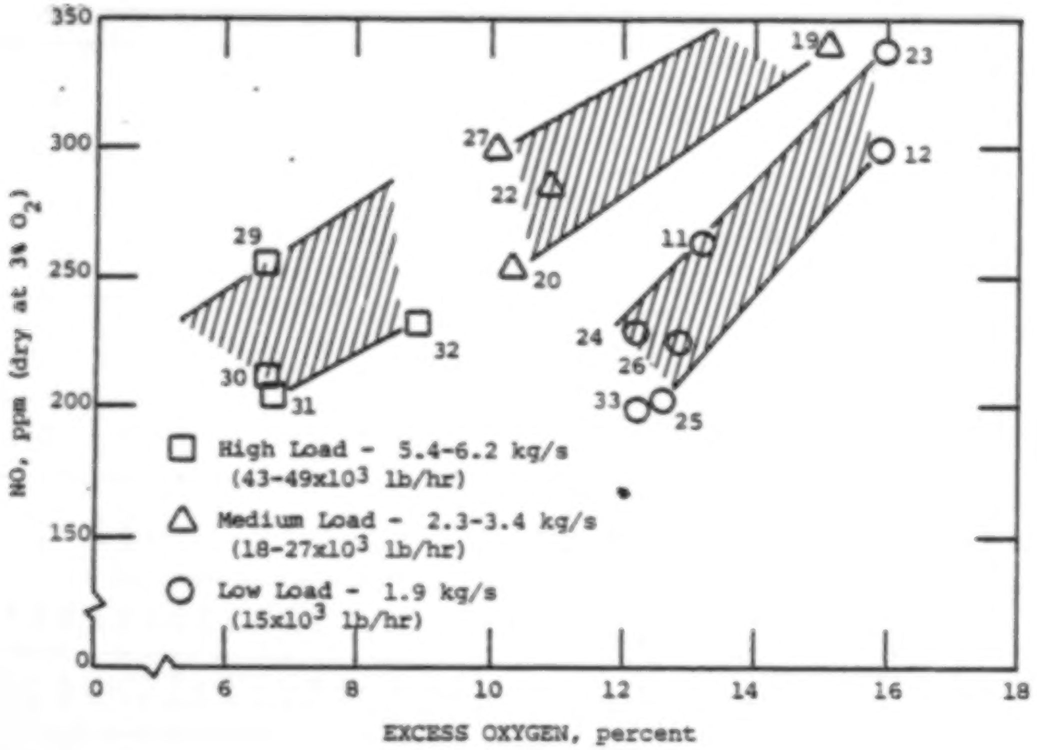


Figure 5.4-3. Nitric oxide emissions vs. excess O_2, University of Wisconsin, Eau Claire, eastern coal.

unburned coal which were bordered by thin ribbons of intense combustion. These areas of intense combustion may have generated much more NO than an evenly burning fuel bed. Figure 5.4-4 is a plot of NO vs. excess O_2 for western coal, with normal operating conditions indicated by test numbers 1, 2, and 7. Raising the excess O_2 level resulted in higher NO emissions at medium [3.2 to 3.3 kg/s (25 to 26×10^3 lb/hr) steam flow] and high loads [3.8 to 4.4 kg/s (30 to 35×10^3 lb/hr) steam flow], while in the single case where it was possible to lower the excess O_2 (test 3) the NO emissions were substantially lowered.

Figure 5.4-5 is a comparison of NO emissions vs. load for eastern and western coals. It must be noted that the trend of increasing NO emissions with increasing load for eastern coal is misleading as the data does show a decrease in NO emissions at loads of 5.4 to 6.2 kg/s (43 to 49×10^3 lb/hr) steam flow; however, it was not possible to reach loads of that magnitude with western coal so only the comparable load ranges are plotted. The higher average NO emissions with eastern coal may be due either to the higher fuel nitrogen content of the eastern coal or that the eastern coal exhibited much better combustion in this unit.

5.4.6 Sulfur Oxides Emissions

The fuel analyses (Table 2-1) show that the eastern coal averages 3.9 times higher in fuel sulfur content than the western coal. If the SO_x results from Table 5.4-4 are compared for medium loads [4.4 kg/s (35×10^3 lb/hr) steam on eastern and 3.2 kg/s (25×10^3 lb/hr) steam on western] over a range of excess air levels, the eastern coal averages 3.55 times the western coal in SO_x emissions. This indicates that a greater percentage of the fuel sulfur in eastern coal may be converted to organic sulfur oxides than with western coal; however, the results show that this eastern coal emits an average of 2445 ppm SO_x at 3% excess O_2, while the western coal emits only an average of 688 ppm SO_x at 3% excess O_2.

It appears, from examining the data, that variations in the fuel sulfur content are as much a factor as load and excess O_2 changes in giving different SO_x results for each coal. The western coal results must be treated

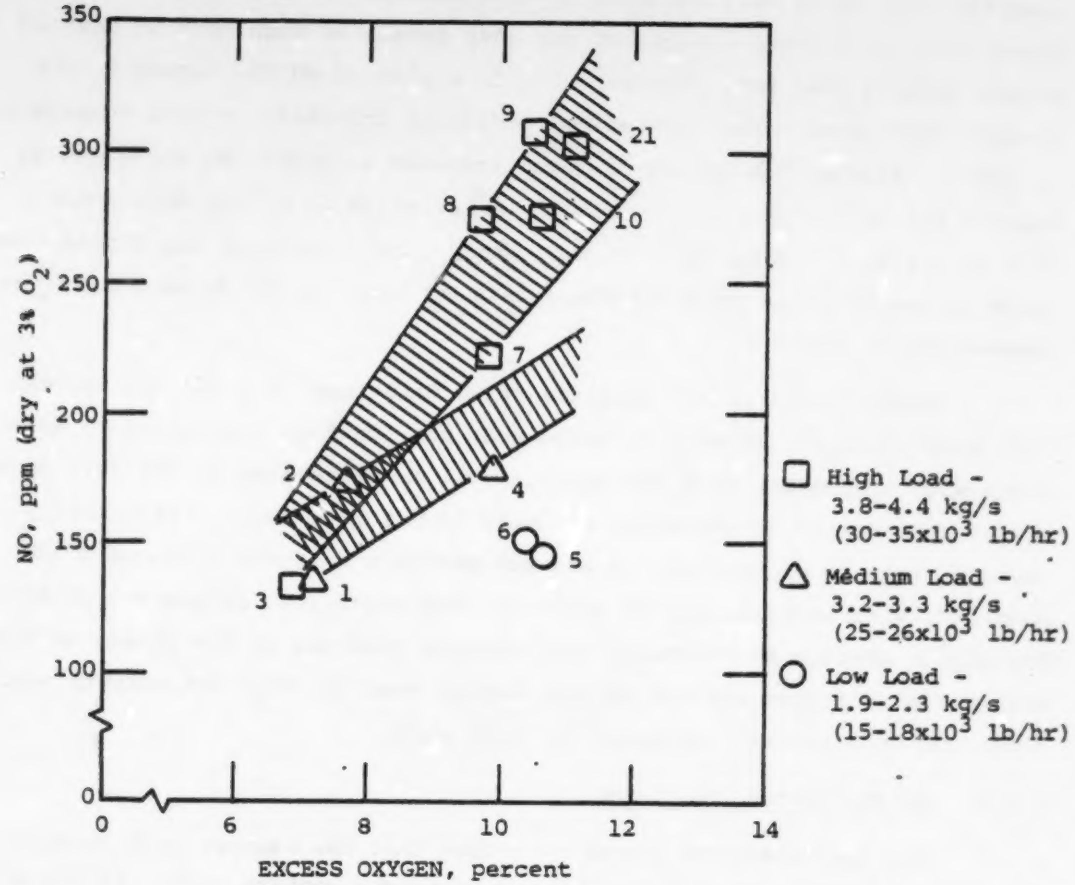


Figure 5.4-4. Nitric oxide emissions vs. excess O_2, University of Wisconsin, Eau Claire, western coal.

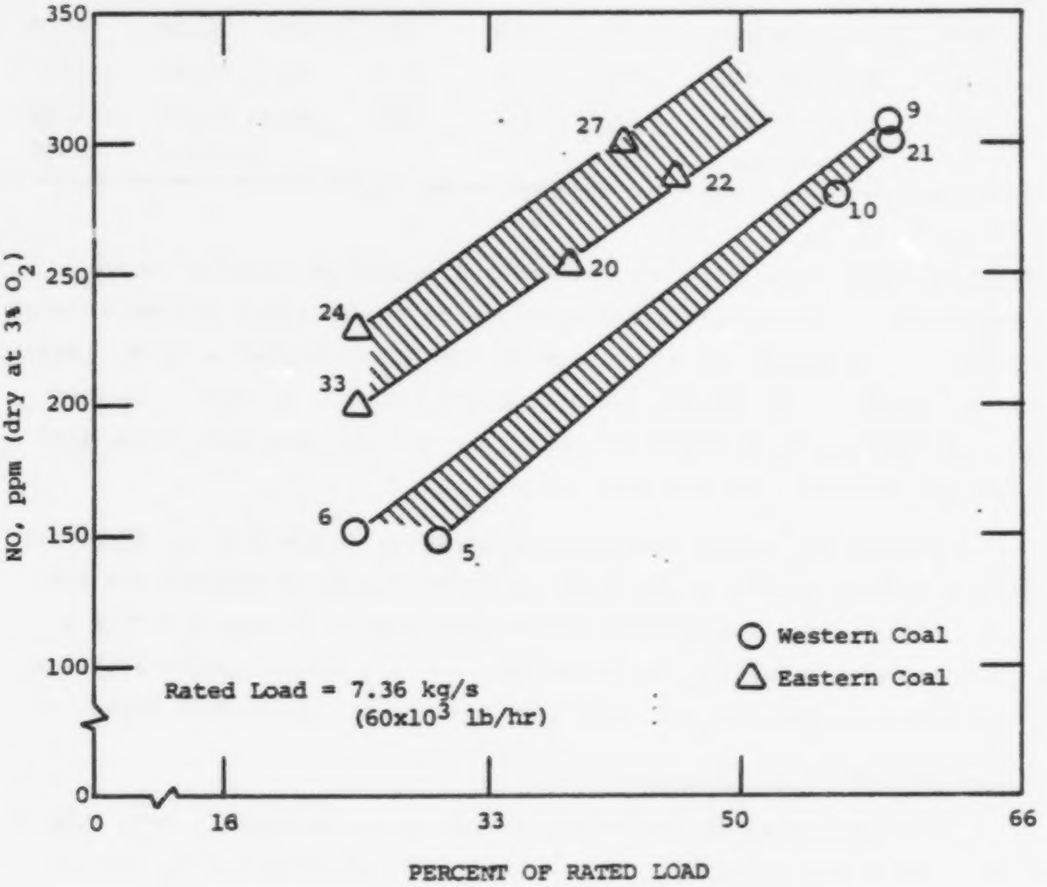


Figure 5.4-5. Nitric oxide vs. percent of rated load, University of Wisconsin, Eau Claire.

TABLE 5.4-4. COMPARISON OF SO_x EMISSIONS FOR SIMILAR LOAD RANGES

WESTERN COAL				EASTERN COAL			
Load kg/s	Load (10^3 lb/hr)	O_2	SO_x, ppm at 3% O_2	Load kg/s	Load (10^3 lb/hr)	O_2	SO_x, ppm at 3% O_2
4.4	(35)	Low, 6.9%	530	3.2	(25)	Low, 10.1%	2520
4.4	(35)	Med, 10.7%	760	3.4	(27)	Med, 12.2%	2622
4.4	(35)	High, 11.1%	775	3.2	(25)	High, 15.0%	2195
		Average	688			Average	2445

carefully in cases where more than 10% of the sample is reported as SO_3. In these cases, it is possible that some of the sample could be lost through volatilization of the SO_2 or conversion of the SO_2 to sulfurous acid, instead of sulfuric acid, which may not react properly with the titrant. In this report, the samples which contained more than 10% SO_3 have been eliminated from the data analysis and the data plots.

A plot of SO_x versus excess O_2 is shown in Figure 5.4-6. There are no clearly defined trends in the data; however it does illustrate the differences in SO_x levels for eastern and western coals. Figure 5.4-7 is a plot of SO_3 versus excess O_2 and shows that the SO_3 concentration increases with increases in excess O_2 for both the eastern and the western coals.

5.4.7 Carbon Monoxide Emissions

The CO emissions for eastern coal are shown in Figure 5.4-8. The highest CO emissions occurred at the lowest loads or at excess O_2 levels that were either higher or lower than "normal" operating conditions. The high CO levels at low loads and for the low excess O_2 conditions were due to the poor mixing of fuel and air. The high CO emissions at high air flow were caused by a high air stream velocity which tended to agitate the fuel bed and quench CO combustion to CO_2. The highest CO level for "normal" operating conditions was 550 ppm (corrected to 3% O_2), but this was under a low load condition. The average CO level for "normal" operation was 226 ppm (corrected to 3% O_2).

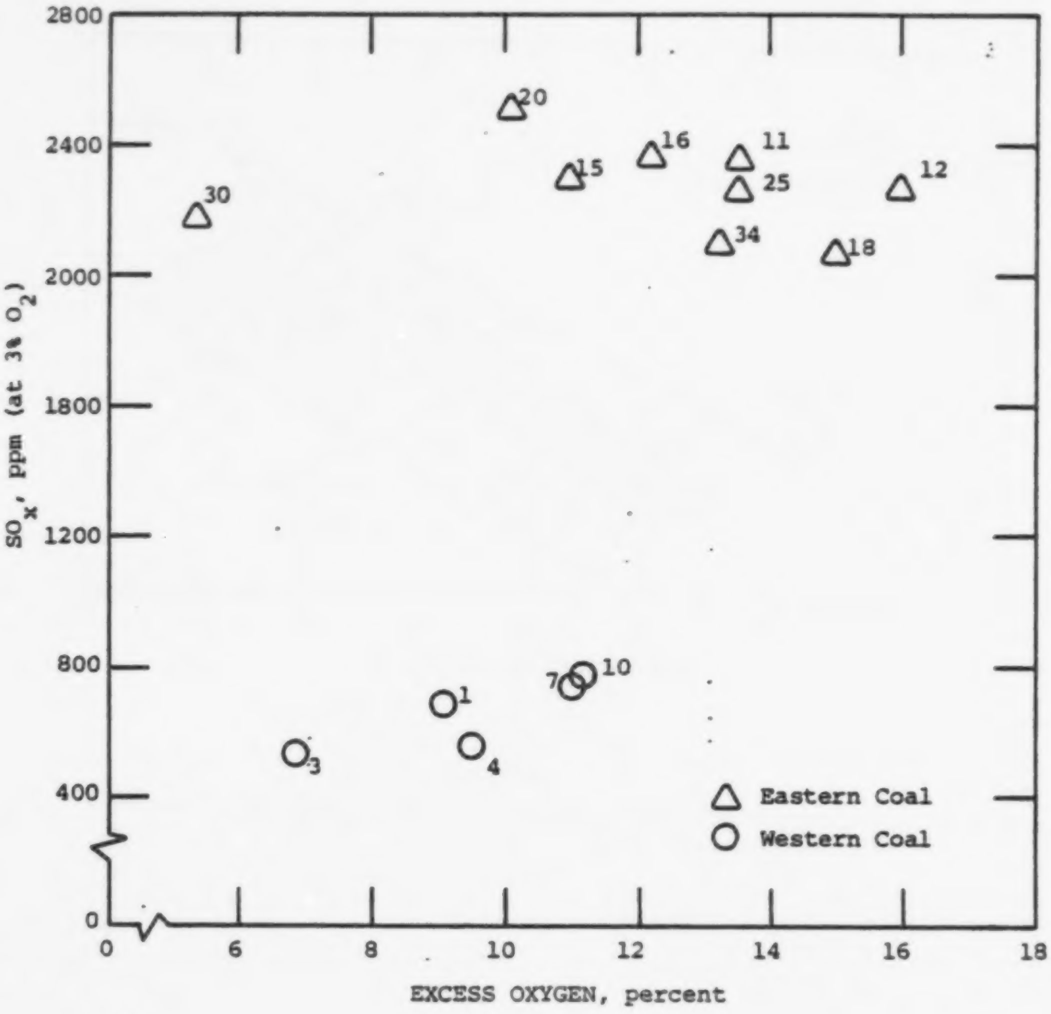


Figure 5.4-6. SO$_x$ emissions vs. excess O$_2$, University of Wisconsin, Eau Claire.

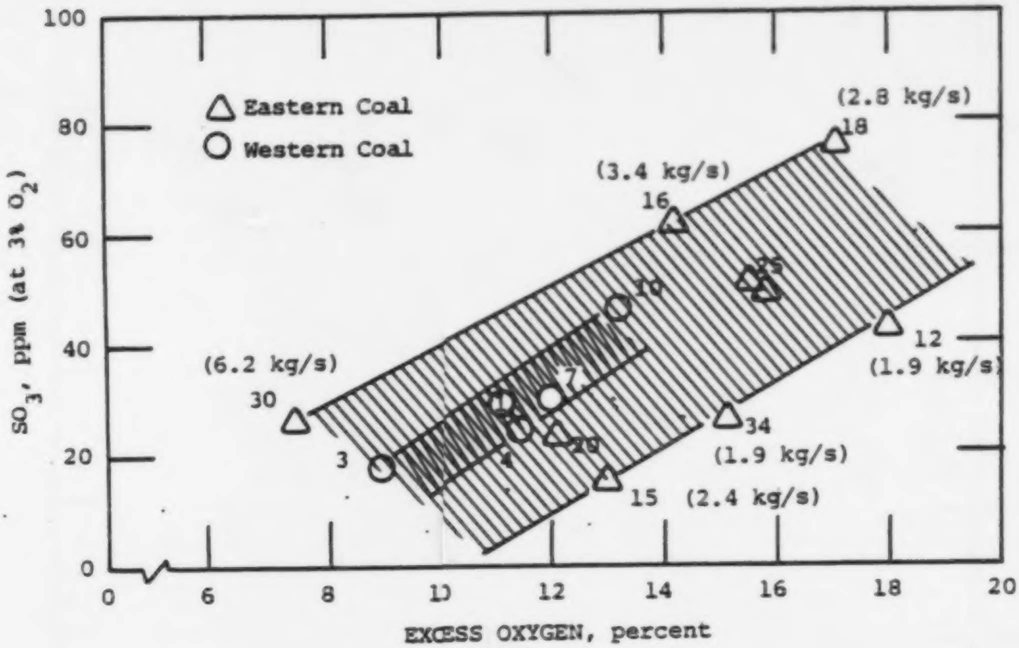


Figure 5.4-7. SO_3 component of SO_x emissions, University of Wisconsin, Eau Claire.

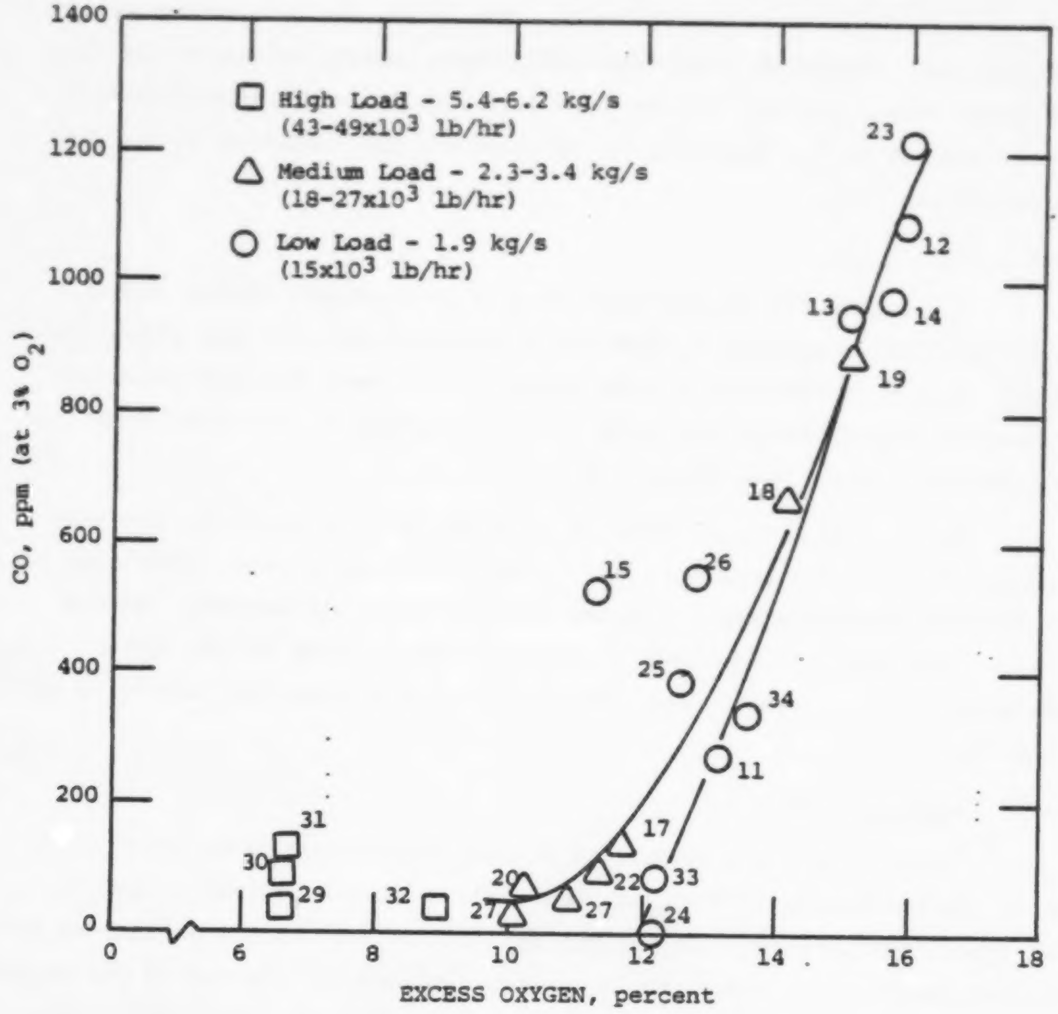


Figure 5.4-8. Carbon monoxide emissions vs. excess O_2, University of Wisconsin, Eau Claire, eastern coal.

The CO emissions for western coal, Figure 5.4-9, do not show a definite relationship to excess O_2 levels; however, it can be seen that the CO levels increase as the unit load increases. This situation is opposite to the trends observed on eastern coal. The reason for this change is the extremely poor combustion conditions which were present at medium and high load ranges while burning the western coal. The CO levels varied from 48 to 1143 ppm (at 3% O_2) depending on the load and the condition of the fuel bed during the test.

5.4.8 Excess O_2

The excess air in this type of unit is generally higher than for pulverized coal or spreader stoker units because there are more places where the air can get by the fuel without mixing, e.g., near the side walls and through air dampers which are under the back portion of the grate where the fuel bed has already been burned out.

The excess air also tends to be higher at low loads for the same reasons. At low loads the fuel bed is very short and a large percentage of the grate is available for air to get through leaky air dampers. As the load is increased, the fuel bed lengthens, covering more of the grate and causing more turbulence and better mixing of air and fuel particles above the grate.

5.4.9 Particulates

Table 5.4-5 is a summary of all the particulate tests which were run at the University of Wisconsin-Eau Claire. Loads, excess O_2 levels, fuel types, and particulate emissions for each test by the total and EPA Method 5 procedures are indicated. The total particulates are the sum of the weights of the filter after a 616 °K (650 °F) bake, the impinger water catch, the probe, cyclone, flask, and filter holder top rinsings, and the particulate collected in the flask. All rinsings were done first with acetone and then with water. All liquids were boiled down and dessicated to dryness before weighing. The Method 5 EPA particulates are the sum of the weights of the

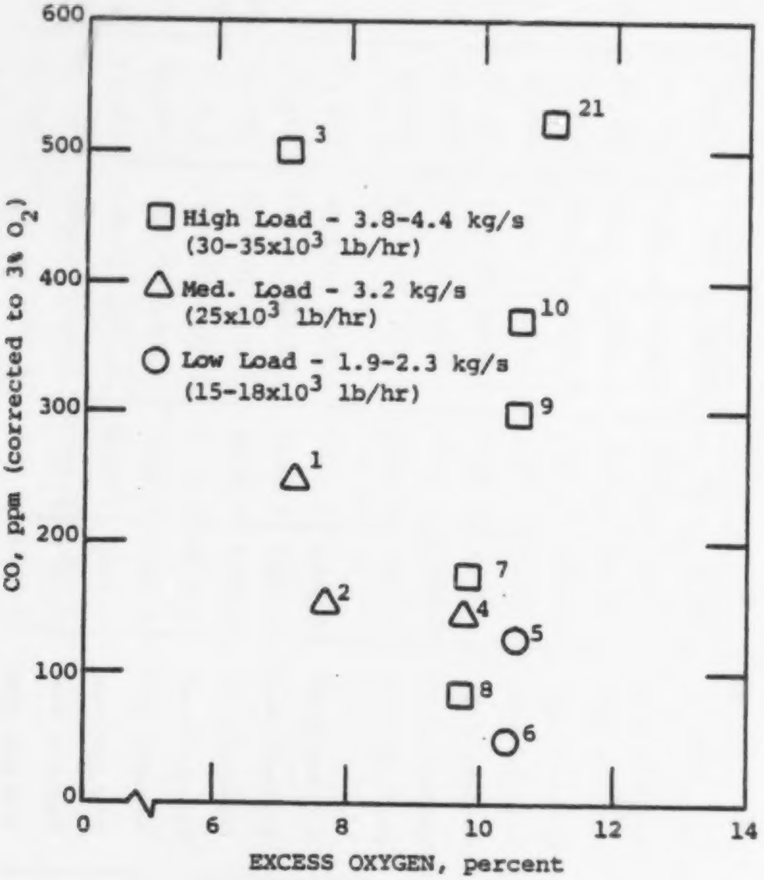


Figure 5.4-9. Carbon monoxide emissions vs. excess O_2, University of Wisconsin, Eau Claire, western coal.

TABLE 5.4-5. PARTICULATE EMISSIONS DATA SUMMARY FOR EAU CLAIRE

Test	Steam Load		O_2		Particulate Emissions						
					lb/MBtu		g/Mcal		ng/J		
No.	kg/s	(10^3 lb/hr)	(%)	Fuel	Total	EPA	Total	EPA	Total	EPA	Sulfates
2	3.2	25	7.7	Western coal	0.2574	0.1786	0.4622	0.3226	110.42	77.07	33.35
3	3.8	30	7.1	Western coal	0.2175	0.1456	0.3926	0.2617	93.79	62.52	31.27
5	2.3	18	10.6	Western coal	0.2414	0.1586	0.4335	0.2867	103.56	68.49	35.07
7	4.4	35	9.8	Western coal	0.3394	0.2743	0.6120	0.4942	146.20	118.06	28.14
8	4.0	32	9.7	Western coal	0.4899	0.3620	0.8841	0.6520	211.20	155.76	55.44
9	4.4	35	10.5	Western coal	0.6930	0.6501	1.2488	1.1711	298.33	279.77	18.56
10	4.2	33	10.6	Western coal	0.9045	0.7643	1.6297	1.3770	389.33	328.96	60.37
11	1.9	15	13.2	Eastern coal	0.3986	0.3081	0.7165	0.5546	171.17	132.49	38.68
14	1.9	15	15.7	Eastern coal	1.3327	1.1911	2.4059	2.1448	574.75	512.37	62.38
17	3.2	25	11.7	Eastern coal	0.4285	0.4188	0.7728	0.7543	184.62	180.20	4.42
19	2.3	18	15.1	Eastern coal	1.3129	1.2333	2.3633	2.2203	564.57	530.42	34.15
27	3.2	25	10.1	Eastern coal	0.8870	0.8884	1.5986	1.600	381.88	382.18	-0.3
28	2.3	18	9.8	Eastern coal	0.3504	0.3046	0.6325	0.5485	151.10	131.03	20.07
30	6.2	49	6.6	Eastern coal	2.7557	2.1353*	3.8929	3.8442*	929.98	918.35*	11.63
32	5.4	43	6.7	Eastern coal	0.6925	0.5835*	1.2471	1.0510*	297.93	251.07*	46.86
33†	1.9	15	12.2	Eastern coal	0.3251	0.2800	0.5877	0.5044	140.40	120.50	19.9

*No 419 °K (250 °F) bake weight available for EPA Method 5 calculation.

†No blank filter weight available.

filter after a 394 °K (250 °F) bake, the probe, cyclone, flask, and filter holder top rinses, and the particulates collected in the flask. The rinsings were done only with acetone. The liquid was boiled down and dessicated to dryness before weighing.

Figures 5.4-10 and 5.4-11, particulate emissions by EPA Method 5 vs. excess O_2 and load respectively, indicate that at a constant excess O_2 level, an increase in load will result in an increase in particulate emissions and, similarly, at a constant load level an increase in excess O_2 will result in an increase in particulate emissions. These results are valid for both the eastern and western coal except for the medium load range [3.2 kg/s (25×10^3 lb/hr) steam flow] with eastern coal where the particulate emissions were higher at the lower excess O_2 level.

Test numbers 30 and 31 do not follow the EPA Method 5 procedures in that the filters were baked at 616 °K (650 °F) before they were weighed, this may have resulted in slightly lower weights. Test number 30 also differs considerably from the other tests in the amount of particulate matter collected by the cyclone separator and flask. The particulate matter collected was nearly three times the weight of that collected in any of the other tests. Examination of the raw data does not show any discrepancies in procedure so the result has been included in the data presentation.

5.4.10 Efficiency

The unit efficiency varied from 69.34% to 78.51% on eastern coal and from 69.89% to 78.34% on western coal. Efficiencies were calculated for only a selected number of tests. Figure 5.4-12 shows the variation of efficiency with load for both coals. Referring to this figure, the change in efficiency with increasing load is similar for both eastern and western coals for loads ranging from 1.9 to 3.8 kg/s (15 to 30×10^3 lb/hr) steam flow. At loads above 3.8 kg/s (30×10^3 lb/hr) steam flow, the unit efficiency on eastern coal remains constant at approximately 78% while the unit efficiency on western coal drops dramatically at loads between 3.8 and 4.4 kg/s

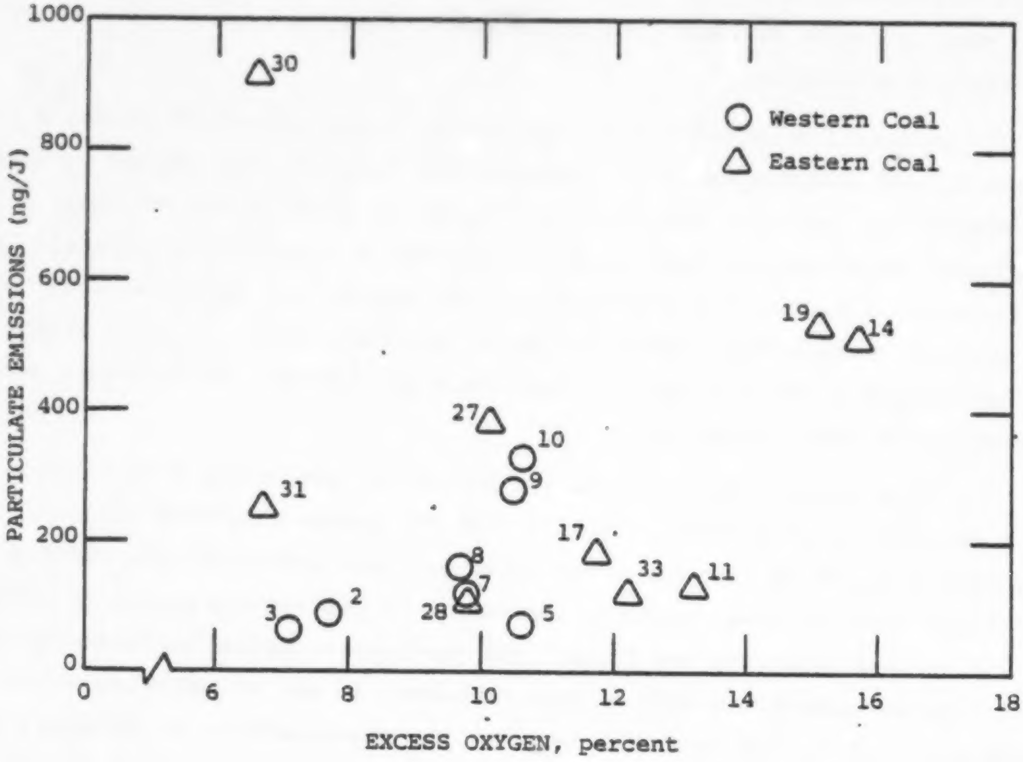


Figure 5.4-10. Particulate emissions vs. excess O_2, University of Wisconsin, Eau Claire.

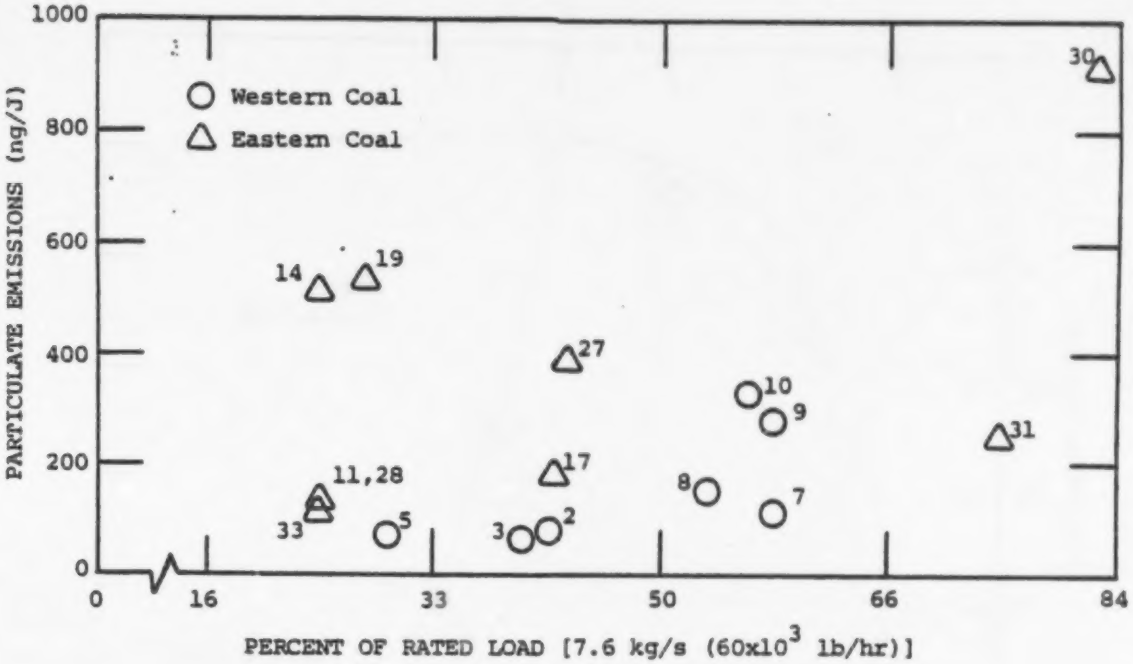


Figure 5.4-11. Particulate emissions vs. percent rated load, University of Wisconsin, Eau Claire.

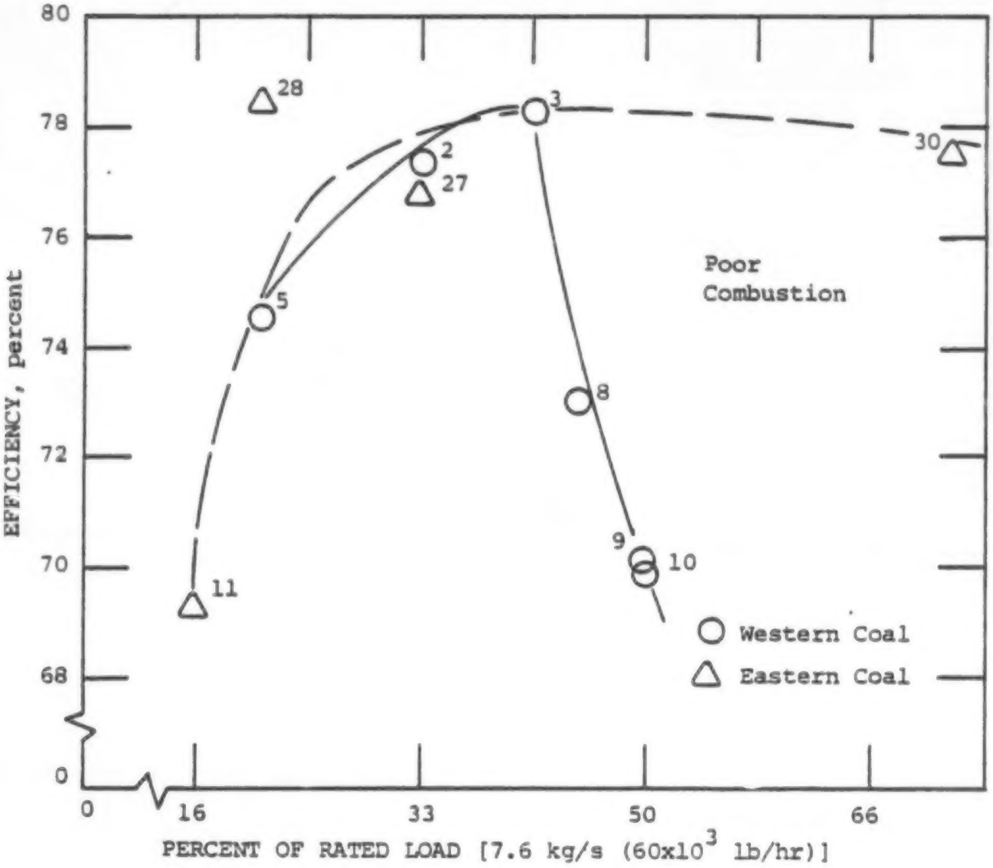


Figure 5.4-12. Boiler efficiency vs. percent rated load, University of Wisconsin, Eau Claire.

(30 and 35x10^3lb/hr) to only 70%. The drop in efficiency on western coal was the result of higher stack gas temperatures, higher excess O_2 levels, and higher gas velocities. These conditions were created by the need to force more air through the fuel bed to try to improve the very poor combustion which was experienced with western coal.

5.4.11 Operational Difficulties

Because this unit is part of a central heating unit, the loads were affected a great deal by the ambient temperature. It was necessary for the plant personnel to switch fuels on four occasions in order for the KVB crew to obtain as complete a test as possible with the load conditions that were available.

Testing began on western coal with loads of 3.2 kg/s (25x10^3 lb/hr) steam flow. The load was then increased to 4.4 kg/s (35x10^3 lb/hr) steam flow by venting steam through the roof of the building. This practice is very expensive for the plant and was halted after several tests. The unit was then loaded with eastern coal as there was insufficient load to continue testing western coal. Tests in the 1.9 to 3.4 kg/s (15 to 27x10^3 lb/hr) steam flow range were run on the eastern coal. The plant load began to increase at this point so the unit was reloaded with western coal and attempts were made to run high loads [> 4.4 kg/s (35x10^3 lb/hr) steam flow]. The tests were discontinued because of operational problems. The unit was reloaded with eastern coal and a series of low, medium, and high load tests were run to complete the test schedule.

No operational difficulties with eastern coal burning were experienced. The eastern coal was easy to handle, it stored well, did not clog the conveyor system, did not show a tendency to segregate, and fed easily into the unit. The coal sizing was good with few fines. It exhibited good ignition characteristics with ignition occurring under the arch uniformly across the boiler. The tendency of this coal to swell encouraged the combustion which was very uniform and the fuel bed burned out at the end of the active undergrate air zones with no carryover of fuel into the ash pits. Some clinkers did form and carry into the ash pits but these were easily removed. The ash bed following the burning zone was sufficiently heavy to protect the grate from overheating. Overall, the unit operated very well on eastern coal. It responded well, there were no problems with load swings, and the fire could be banked easily. The major problem on this unit is the lack of precise control over the fuel bed length where the air damper sections are long, in grate sections 3 and 4 from the front of the unit. This could be solved by dividing each of these sections into two separate air dampers. A modification such as this would also help in the burning of western coal; however, the problems on western coal were quite severe and even improved air damper controls might not insure proper combustion.

The western coal was as easy to store and feed into the boiler as the eastern coal; however, there were very severe problems associated with burning the western coal. The unit was set up with the bed thickness at 17.8 to 19.0 cm (7.0 to 7.5 in.) which is about 6.5 cm (3 in.) more than is common on eastern coal. The coal feeder was set on manual and the stoker air dampers were set for more air at the rear of the grate. Ignition of the western coal was poor; it did not occur under the ignition arch. When ignition occurred it was not uniform across the width of the boiler. The area of poor ignition was followed by poor combustion in the main section of the boiler. The areas of the fuel bed which contained fines would burn out creating holes through which the combustion air would pass without mixing with the rest of the fuel bed. This in turn would leave large masses of unburned fuel in the boiler. On many occasions, even by manual raking the fuel bed and opening extra air dampers beneath the fuel bed, these masses of unburned coal were carried into the ash pit where they would burn, causing a safety hazard. In situations where it was possible to burn out the fuel before it reached the ash pit, the grate coverage of the ash from the western coal was not sufficient to protect the grate from overheating. The overall unit operation on western coal was very poor. It was characterized by a large decrease in unit capacity [limited to 4.4 kg/s (35×10^3 lb/hr) steam flow compared to 6.3 kg/s (50×10^3 lb/hr) for eastern], a dramatic decrease in unit efficiency (from 78 to 70%), and a significant increase in operational manpower.

5.5 UNIVERSITY OF WISCONSIN, MADISON

The boiler tested was Boiler No. 2 of the Central Heating Plant on the University of Wisconsin campus located in Madison, Wisconsin.

The boiler was manufactured by Babcock and Wilcox in 1952. The nameplate rating of this boiler is 12.6 kg/s (100,000 lb/hr steam). The boiler, which is depicted in Figure 5.5-1, is fired with a Westinghouse Centrafire spreader stoker with a traveling grate, and is a balanced draft unit. Other specifications are as follows:

- Design pressure - 4.9 MPa (700 psig)
- Steam temperature - 656°K (720°F)
- Actual day-to-day operating pressure - 4.2 MPa (600 psig)
- Boiler heating surface - 131.18 m^2 (1412 sq.ft)
- Economizer heating surface - 518.12 m^2 (5577 sq.ft)
- Stoker grate size - 4.038 m x 4.94 m (13' 3" x 16' 2-1/2")
- Stoker grate area - 19.96 m^2 (214.8 sq.ft)

Base Coal - Vogue, Southern Illinois, Stonefort
Western Coal - Montana Colstrip

5.5.1 Unit Operation

Coal enters the stoker from a hopper above the stoker which is fed by a conveyor system from the coal bunker. Coal is discharged by the feeder to a rotary spreader which throws the coal into the furnace and distributes it uniformly over the grate. Three Westinghouse Centrafire feeders are used with this boiler. The finer particles of fuel burn in suspension and the coarse particles fall to the surface of the fuel bed. The grate surface, with an area of 19.96 m^2 (214.8 sq.ft.) travels from rear to front with ash discharge at the front. Control of coal feed rate distribution over the grate is by adjustment of rotor speed and spill plate adjustment. Overfire air is supplied by a separate blower and can be controlled with a damper.

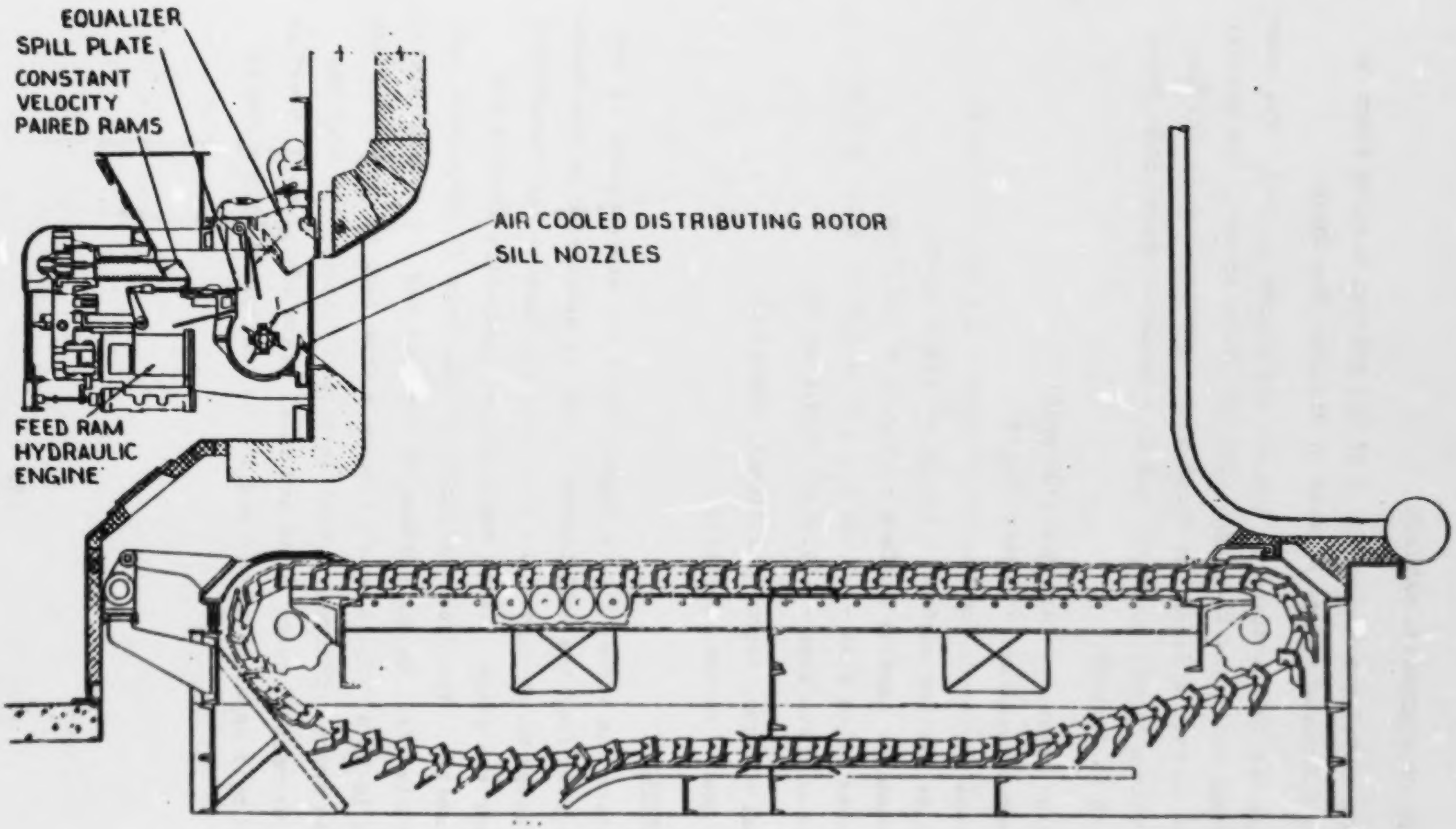

EQUALIZER
SPILL PLATE
CONSTANT VELOCITY PAIRED RAMS
AIR COOLED DISTRIBUTING ROTOR
SILL NOZZLES
FEED RAM HYDRAULIC ENGINE

Figure 5.5-1. Westinghouse Centrafire spreader stoker with traveling grate.

Hot combustion gases travel upward in the furnace. At the top of the boiler, the gases begin a downward pass through an economizer section and then upward through a duct to a common breeching to the stack.

The unit has no dust collection device as such; fly ash drops out at the end of the economizer pass before the flue gases enter the ID fans and is removed by a pneumatic system.

5.5.2 Emission Data

A summary of the emission data is presented in Table 5.5-1 for both western and eastern coal.

The testing was begun with western coal (Montana Colstrip) and the boiler at 7.56 kg/s (60,000 lb/hr) steam output. The boiler was operating in the normal or "as-found" condition. Tests were conducted at three loads - 11.3, 7.56, and 3.78 kg/s (90, 60, and 30×10^3 lb/hr) steam. At each load the excess O_2 was varied from a "normal" to a higher and lower value if possible. At the high load, O_2 variation was limited by the capacity of the induced draft fan. At low load conditions, the bed was very thin or areas of the grate were not covered with coal, so that the O_2 could not be lowered below about 13.5% O_2. No control of the undergrate air was possible except for the damper on the forced draft fan. Figure 5.5-2 is a plot of excess oxygen as a function of boiler load when firing Montana Colstrip coal. A line is drawn through the points representing the normal O_2 condition. The range of O_2 variation possible at each load point is shown. Figure 5.5-3 presents the same information for the Illinois Stonefort coal.

The effect of excess O_2 on NO is shown in Figures 5.5-4 and 5.5-5 for western and eastern coals respectively. Both coals exhibited significant reduction in NO with decreasing O_2. Western coal showed a reduction of 34% in NO_x for a 3.5% reduction in O_2. A 3% decrease in O_2 when firing eastern coal resulted in a reduction of 26% in NO_x. Carbon monoxide as a function of excess oxygen is presented in Figures 5.5-6 and 5.5.7 for eastern and western coals respectively. High CO levels were measured with both

TABLE 5.5-1. EMISSION DATA SUMMARY, UNIVERSITY OF WISCONSIN-MADISON, UNIT 2

Test No.	Date	Load		O_2 percent	CO (ppm)	CO_2 (%)	NO(dry) (ppm)	NO_x* (wet) (ppm)	Percent Combust.	Particulates		SO_x (ppm)	SO_x		Fuel S		Sulfur Retention Factor, percent
		kg/s	(10^3 lb/hr)							(ng/J)	(lb/MBtu)		(ng/J)	(lb/MBtu)	(ng/J)	(lb/MBtu)	
									WESTERN COAL								
1	1-13-76	7.56	60	7.9	111	11.0	341	NA		NA	NA	---					
2	1-13-76	7.56	60	6.5	36	12.3	321	308	23.16	388	0.903	1051	862	2.01	953	2.22	90.5
3	1-14-76	7.56	60	10.9	309	10.1	485	447	20.26	447	0.949	1808					
4	1-14-76	7.56	60	11.4	716	8.6	593	593	15.65	429	1.00						
5	1-15-76	11.33	90	7.2	420	12.1	446	424	44.7	888	2.07	1121	919	2.14	719	1.677	122
6	1-16-76	11.33	90	7.5	391	12.3	425	---	27.98	742	1.73	1146					
7	1-21-76	3.78	30	13.6	1619	6.7	403	396	16.42	451	1.06	600	492	1.147	908	2.115	54
8	1-22-76	10.08	80	9.7	634	10.8	482	417	36.05	897	2.09	1540					
9	1-22-76	10.08	80	6.2	380	11.5	294	274	49.14	725	1.69	1576					
10	1-23-76	3.78	30	11.5	1244	7.4	406	422	———	---	----	1407	1155	2.69	1224	2.85	94
	Average	7.06	64	9.44	577		420		29.17	610	1.44	1281	857	1.997	951	2.216	90
									EASTERN COAL								
11	1-26-76	7.56	60	10.0	29	10.3	450	464	44.9	674	1.57	2085	1711	3.99	2119	4.937	80.8
12	1-26-76	7.56	60	12.0	200	8.4	511	538	49.13	1060	2.47	2146					
13	1-27-76	7.56	60	7.8	0	11.5	401	411	51.22	455	1.06	--					
14	1-28-76	11.33	90	7.3	1106	11.1	379	397	49.64	738	1.72	2119	1739	4.053	2195	2.114	79
15	1-29-76	11.33	90	9.1	215	10.3	436	454	46.37	644	1.50	2345	1924	4.484	2215	5.162	86.9
16	1-29-76	11.33	90	10.3	236	9.4	505	540	47.56	880	2.05	--					
17	1-30-76	3.78	30	14.7	484	6.9	404	404	56.61	605	1.41	3094					
18	2-2-76	7.56	60	11.3	13	9.1	445	517	45.63	584	1.36	--					
19	2-2-76	3.78	30	15.8	1275	6.4	508	519	———	---	--	2963	2431	5.665	2144	4.995	112
	Average	7.17	63	10.98	445		449		48.89	704	1.64	2458	1952	4.548	2168	5.052	90
Difference of Western and Eastern, %				-14	+23		-6		-40	-12		-48	-56		-56		

*Corrected for low converter efficiency.

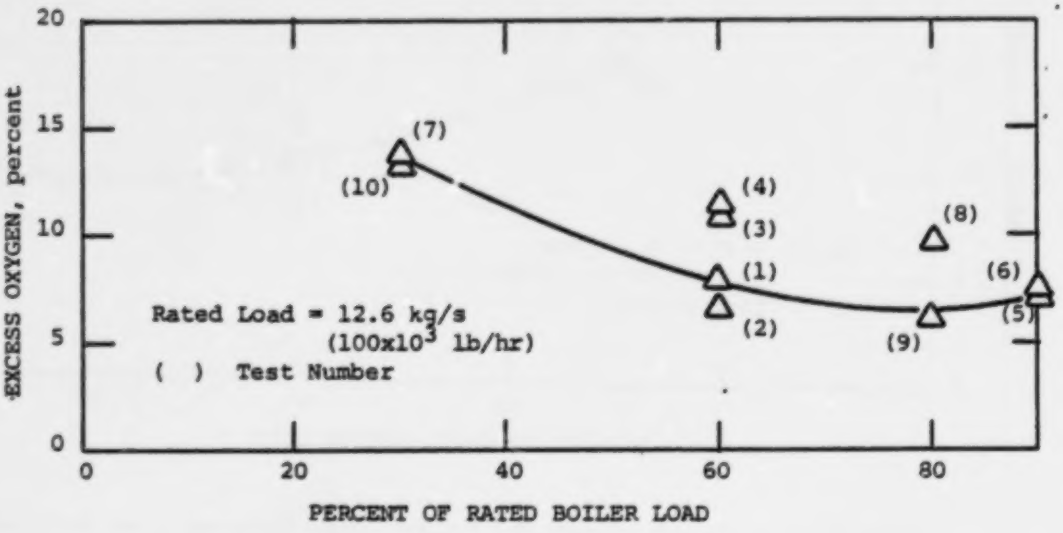


Figure 5.5-2. Excess oxygen vs. boiler load, University of Wisconsin, Madison, Unit 2, Montana Colstrip coal.

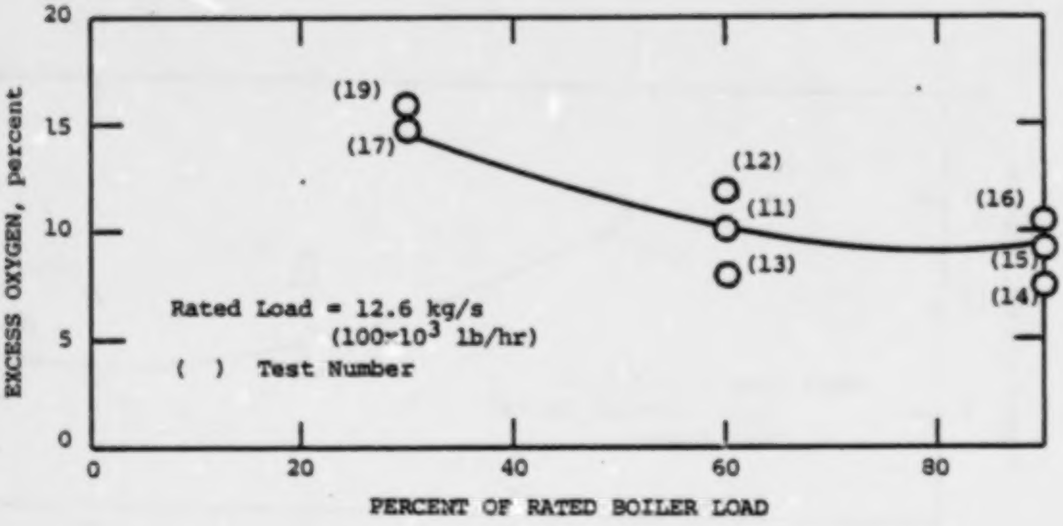


Figure 5.5-3. Excess oxygen vs. boiler load, University of Wisconsin, Madison, Unit 2, Illinois Stonefort coal.

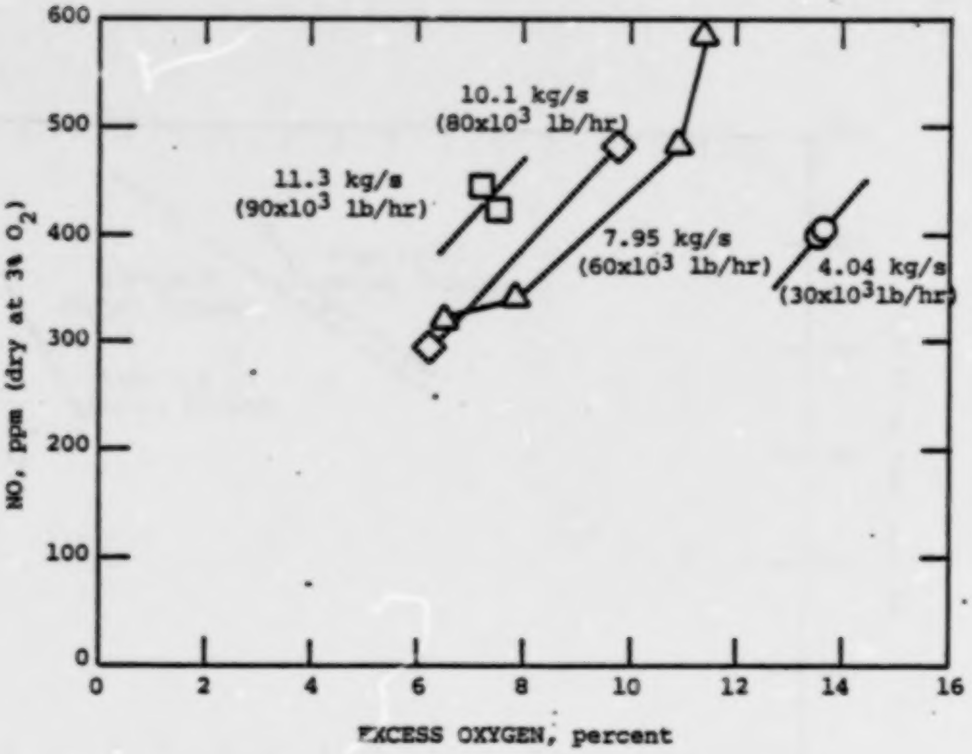


Figure 5.5-4. Nitric oxide vs. excess oxygen, University of Wisconsin, Madison, western coal.

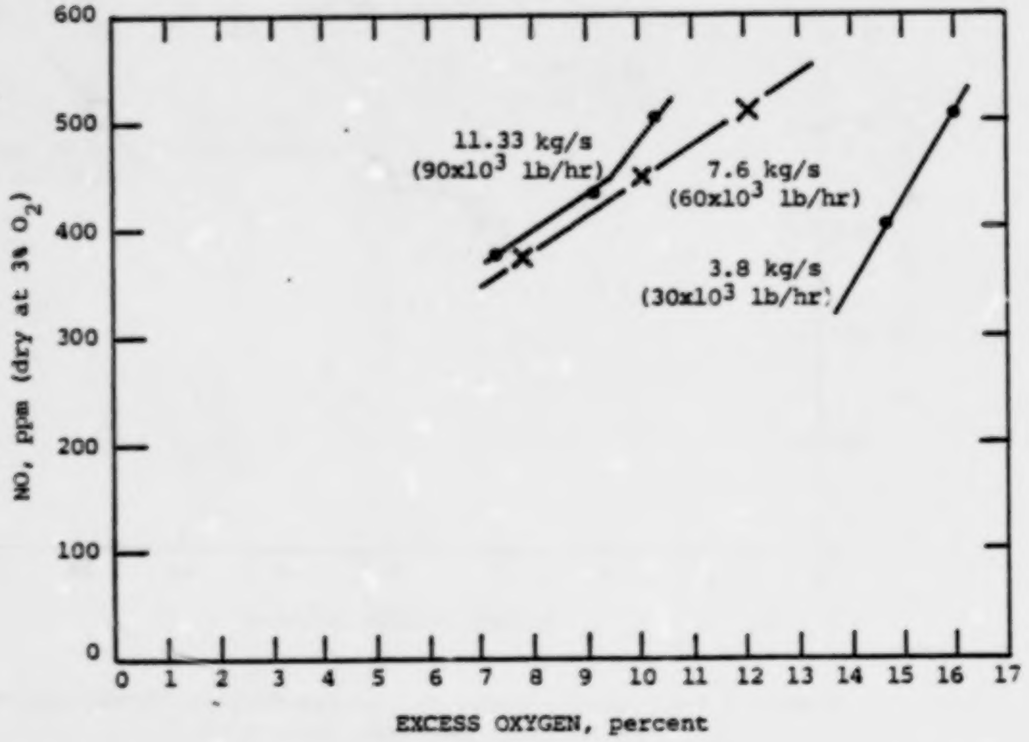


Figure 5.5-5. Nitric oxide vs. excess oxygen, University of Wisconsin, Madison, eastern coal.

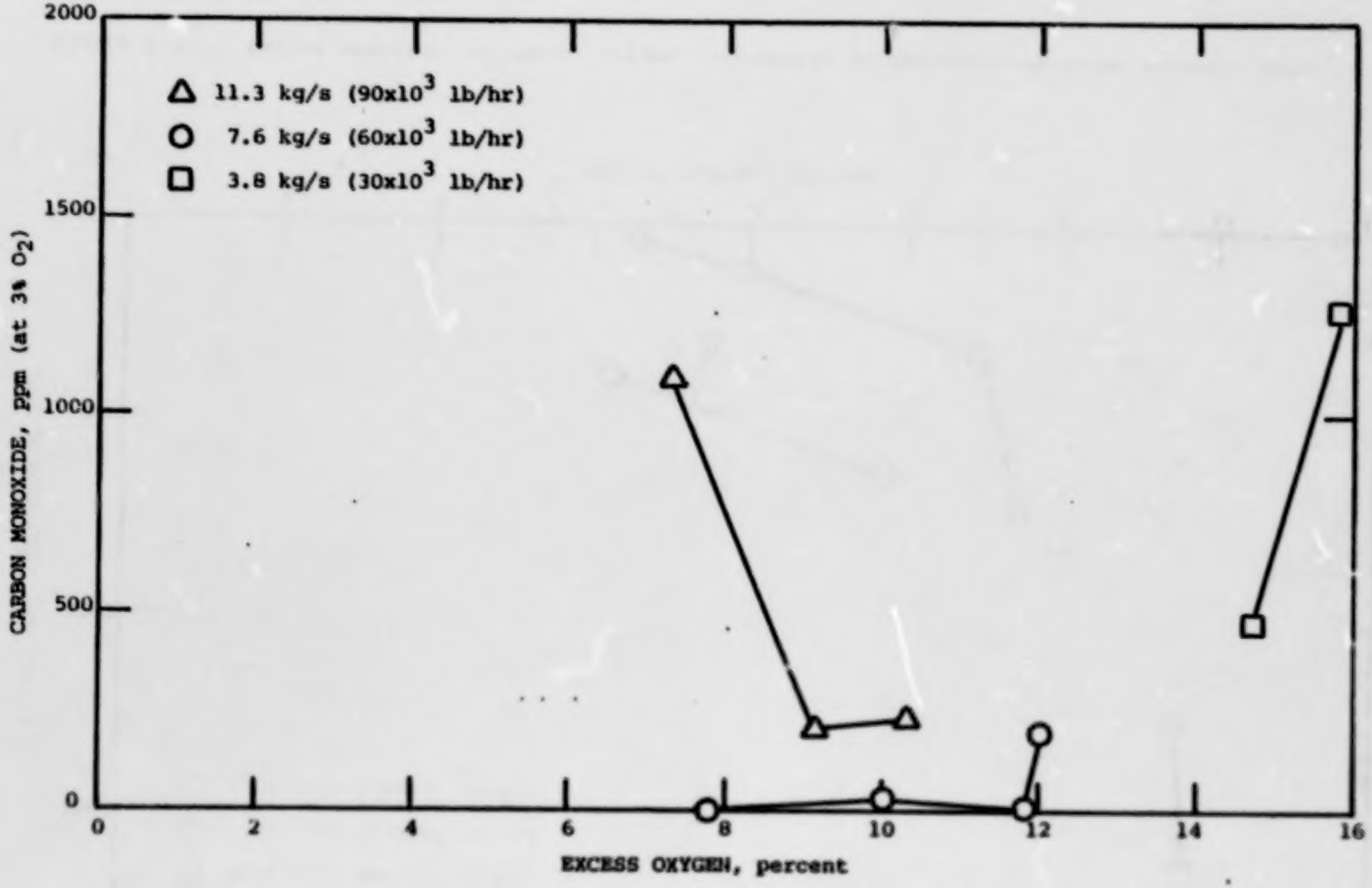


Figure 5.5-6. Carbon monoxide vs. excess oxygen, University of Wisconsin, Madison, eastern coal.

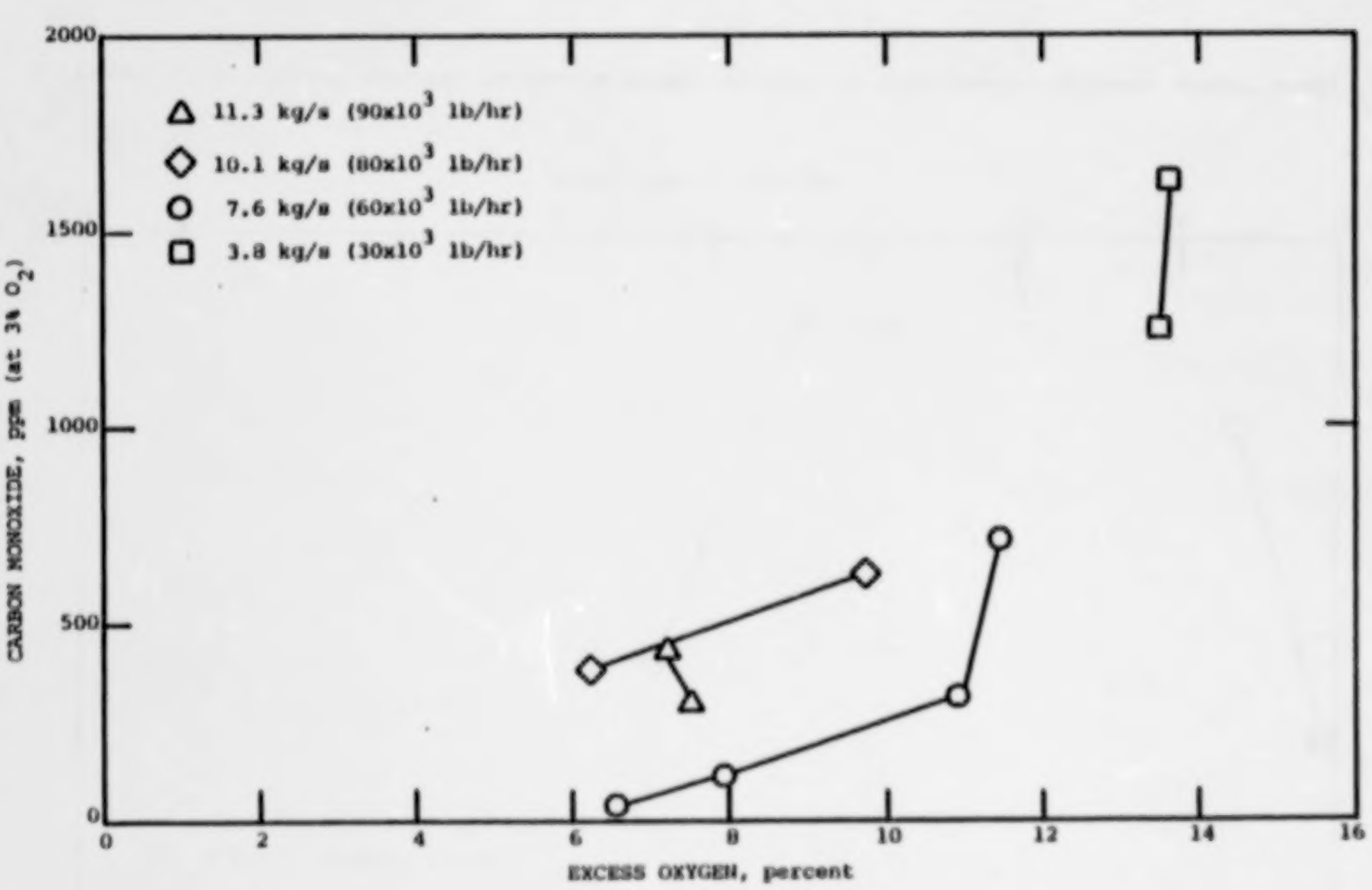


Figure 5.5-7. Carbon monoxide vs. excess oxygen, University of Wisconsin, Madison, western coal.

coals at high excess air, low load conditions. The high CO is due to portions of the grate being uncovered which probably leads to quenching and incomplete combustion. Figure 5.5-8 shows the effect of boiler load on NO emissions for both western and eastern coals.

Results of the particulate tests are presented in Figure 5.5-9 where particulate loading as a function of boiler load is shown for both western and eastern coals. The numbers in parentheses refer to the excess oxygen percentage for each test. The particulate loading is seen to be higher for eastern coal at the low and intermediate loads and approximately the same as western coal at the high load condition. The sulfur oxide test results are presented in Table 5.5-2. A summary of the SO_x data was presented in Table 5.5-1 where average SO_x data are tabulated. Fuel samples were taken for each test and were analyzed for sulfur content to complete the analysis of this data.

The hydrocarbon instrument was inoperative until the last week of testing so that no hydrocarbon data could be taken during the normal test period. When the instrument was repaired, two days were used to measure HC emissions with both western and eastern coals. The boiler load was varied and HC measurements made at 3 loads: 5.0, 7.6, and 11.3 kg/s (40, 60, and 90x10^3 lb/hr). The hydrocarbon data show the same trend as the CO data. At low load and high excess O_2, the unburned hydrocarbon emissions increase. This is thought to be due to combustion quenching by the air. The results of the HC measurements are shown below:

Load		Eastern Coal		Western Coal	
kg/s	(10^3 lb/hr)	O_2(%)	HC (corr. ppm)	O_2(%)	HC (corr. ppm)
5.0	40	15.	114	13.8	125
7.6	60	12.7	54	11.3	18
11.3	90	9.7	48	—	—
11.3	90	8.7	44	8.8	44

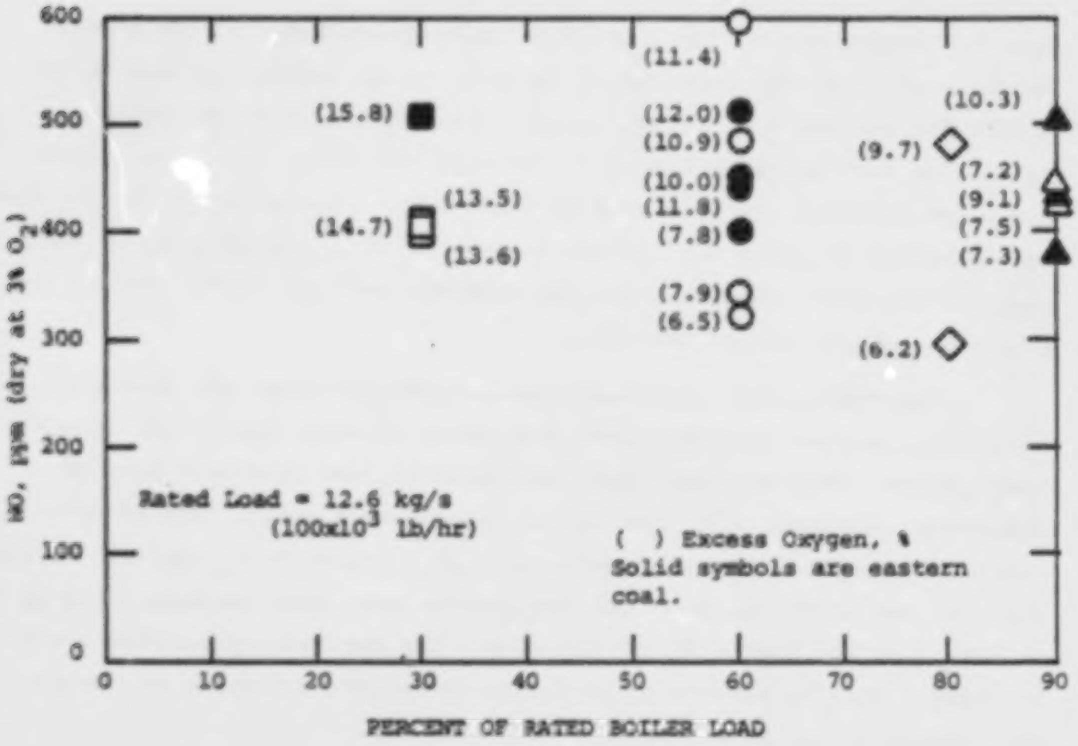


Figure 5.5-8. Nitric oxide vs. boiler load, University of Wisconsin, Madison, eastern and western coals.

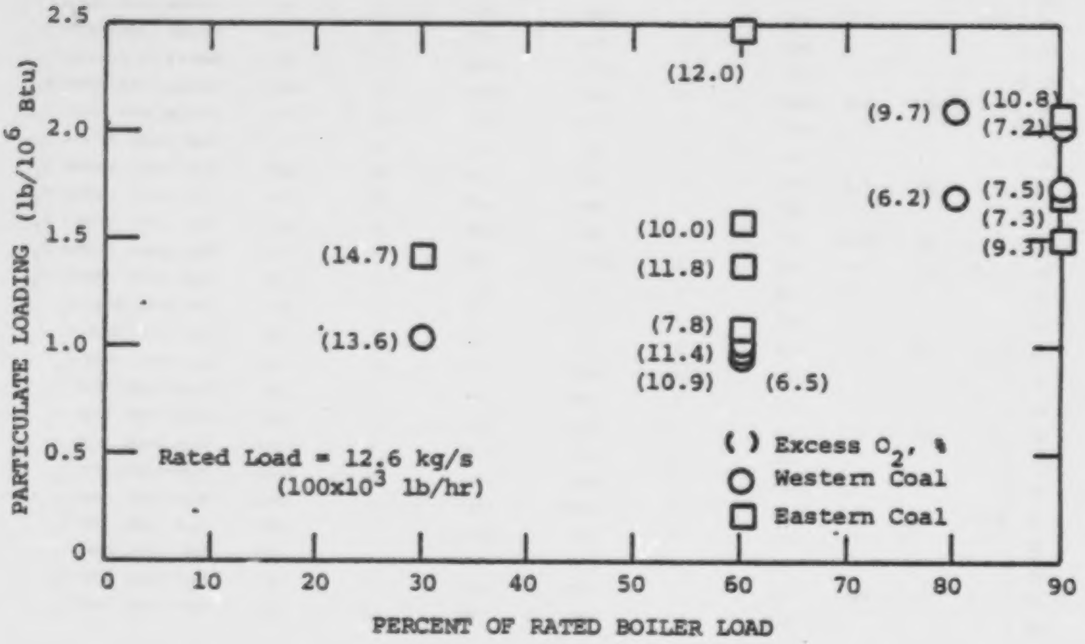


Figure 5.5-9. Particulate loading vs. boiler load, University of Wisconsin, Madison.

TABLE 5.5-2. SO_x DATA SUMMARY
UNIVERSITY OF WISCONSIN-MADISON, UNIT NO. 2

Test No.	kg/s	(10^3lb/hr)	O_2 per-cent	SO_2 (uncorr. ppm)	SO_3 (uncorr. ppm)	SO_x (uncorr. ppm)	SO_2 (corr. ppm)	SO_3 (corr. ppm)	SO_x (corr. ppm)	Test Description
					WESTERN COAL					
1A	7.6	60	7.7	854	2	856	1153	3	1156	Medium load, normal O_2
1B				632	2	634	853	3	856	Medium load, normal O_2
1C				842	2	844	1137	3	1140	Medium load, normal O_2
3A	7.6	60	9.6	1047	9	1056	1653	14	1667	Medium load, high O_2
3B				1168	7	1175	1833	11	1844	Medium load, high O_2
3C				1212	7	1219	1902	11	1913	Medium load, high O_2
5A	11.3	90	7.2	853	2	855	1108	3	1111	High load, normal O_2
5B				862	3	865	1120	4	1124	High load, normal O_2
5C				867	2	869	1127	3	1130	High load, normal O_2
6A	11.3	90	8.05	960	4	964	1228	5	1232	High load, normal O_2
6B		90	8.0	1021	5	1026	1306	7	1313	High load, normal O_2
6C		90	6.9	699	4	703	887	5	892	High load, normal O_2
7A	3.8	30	13.5	247	4	251	593	10	603	Low load, high O_2
7B				238	5	243	571	12	583	Low load, high O_2
7C				250	6	256	600	14	614	Low load, high O_2
8A	10.1	80	9.5	977	5	982	1524	7	1531	High load, high O_2
8B				986	5	991	1538	7	1545	High load, high O_2
8C				981	6	987	1535	9	1544	High load, high O_2
9A	10.1	80	6.7	1284	8	1292	1605	10	1615	High load, low O_2
9B				1223	7	1230	1528	9	1537	High load, low O_2
9C				1255	6	1261	1568	8	1577	High load, low O_2
10A	3.8	30	13.4	597	2	599	1433	5	1438	Low load, high O_2
10B				572	4	576	1316	9	1325	Low load, high O_2
10C				602	6	608	1446	13	1459	Low load, high O_2
					EASTERN COAL					
11A	7.6	60	10.0	1188	3	1191	1936	5	1941	Medium load, normal O_2
11B				1317	9	1326	2147	15	2162	Medium load, normal O_2
11C				1312	8	1320	2138	13	2151	Medium load, normal O_2
12A	7.6	60	12.0	1097	2	1099	2194	4	2198	Medium load, high O_2
12B				1039	4	1043	2078	8	2086	Medium load, high O_2
12C				1069	8	1077	2138	16	2154	Medium load, high O_2
14A	11.3	90	7.3	1505	8	1513	2031	11	2042	High load, low O_2
14B				1497	11	1508	1962	14	1976	High load, low O_2
14C				1809	20	1829	2315	26	2341	High load, low O_2
15A	11.3	90	9.2	1509	—	1509	2293	—	2293	High load, normal O_2
15B				1533	17	1550	2338	26	2364	High load, normal O_2
15C				1547	18	1565	2351	27	2378	High load, normal O_2
17A	3.8	30	14.5	1004	8	1112	2780	21	2801	Low load, high O_2
17B				1078	13	1091	2984	35	3019	Low load, high O_2
17C				1152	3	1155	3455	8	3463	Low load, high O_2
19A	3.8	30	15.5	1170	6	1176	3826	20	3846	Low load, high O_2
19B			15.5	707	5	712	2312	16	2328	Low load, high O_2
19C			16.6	749	6	755	2696	22	2717	Low load, high O_2

5.5.3 Summary of Operational Factors

Normal operation of the boiler when firing coal is conducted at a high excess oxygen percentage to prevent smoking and to assure complete burnout of the coal. When the low excess oxygen test at 7.6 kg/s (60×10^3 lb/hr) was attempted, difficulties were encountered. The operator was requested to lower the air to a level where the air pen and steam pen were coincident on the control room chart. This condition had been satisfactory at a previously higher load.

A patch of unburned coal formed at the rear of the furnace. The low O_2 (4.5% to 5.5%) condition was maintained and the unburned coal patch increased in size. The load then started dropping and the boiler would not respond to load demand. Finally the air was increased to attempt to burn out the unburned patches, but with no success. Grate speed was increased to discharge the unburned coal before clinkers formed. The unburned coal ignited when it dropped into the ash pit, making the pulling of ashes dangerous.

At low to intermediate loads the furnace is not hot enough to ignite the coal in suspension, allowing it to fall to the grate. At these loads the air must be kept at a level to assure rapid heat release to maintain ignition. Ignition of the coal is impaired by the low combustion air temperature [256 to 240°K (0 to -20°F)] and high moisture content of the coal. Any unburned spots in the furnace can rapidly create a large mass of unburned coal which is extremely difficult to burn out even with increased excess air. When low excess O_2 conditions are attempted, the coal bed must be observed carefully to detect any unburned coal patches. If any patches are detected, the test should be aborted and the excess O_2 increased.

During a nontesting period, the traveling grate failed. It appeared that the rear seal failed due to overheating and the broken parts jammed the grate. A total of nine grate links were broken. Two test days were lost while the unit was repaired.

After the boiler was brought back on-line, the left feeder spill plate appeared bent. The feeder-distribution is shown in Figure 5.5-10 and the effect of spill plate position is shown in Figure 5.5-11.

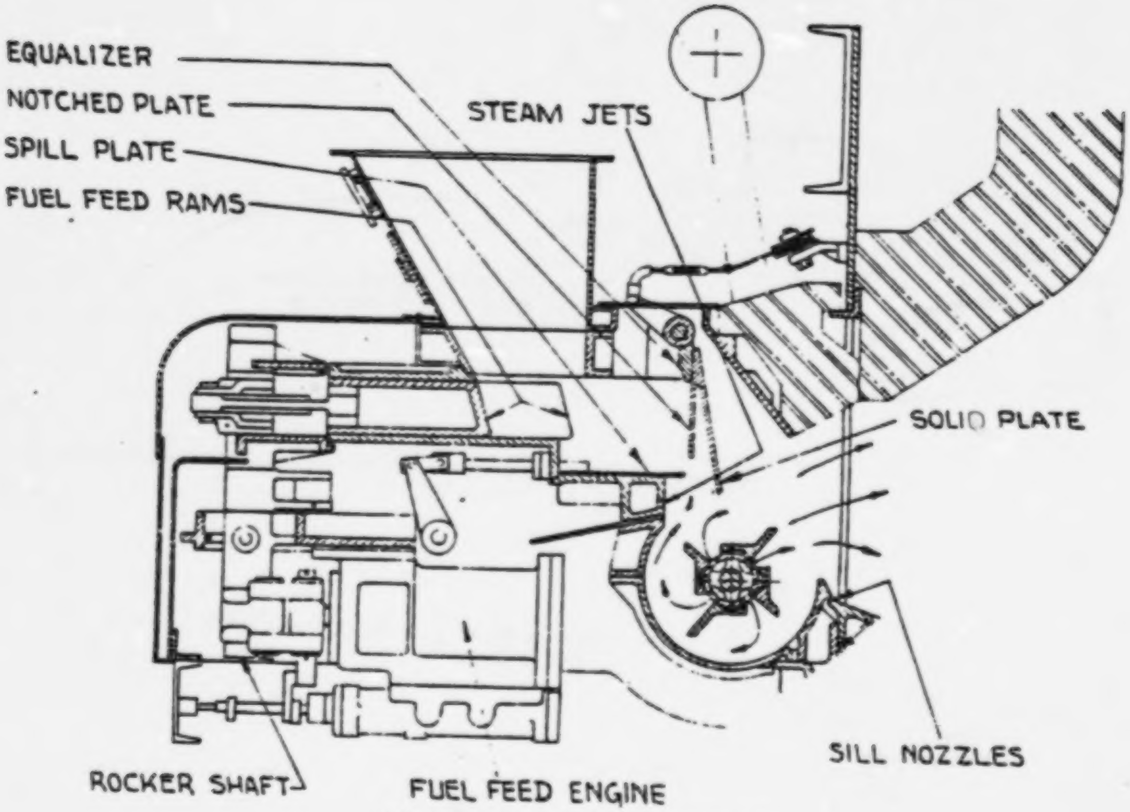
At low load [3.8 gk/s (30×10^3 lb/hr)], a patch of unburned coal accumulated toward the front of the furnace. The left side spill plate was adjusted to try to reduce the coal accumulation in the front of the furnace. The fire was situated too far forward in the furnace resulting in bare grate in the rear. The coal size was such that the spreader could not throw coal to the rear of the furnace through the hot forward zone. Therefore, much of the coal burned in suspension resulting in bare grate areas in the rear. The rotor speed was increased which improved the situation somewhat.

The excess O_2 at low load conditions could not be reduced below about 13% due to the open grate areas. Therefore, only one O_2 level was tested at low load.

The coal trajectory is governed by several spreader variables as shown in Figures 5.5-10 and 5.5-11. The variables include:

- spill plate setting
- rotor speed
- coal size/density
- rotor blade pitch/size

During the testing on eastern coal, extreme smoking occurred when the O_2 was reduced too far. At the high load setting, the O_2 could not be reduced below 7.5% without the smoke indicator pegging upscale. At 6% O_2, the CO instrument was off scale (>2,000 ppm) and the smoke indicator was pegged at 100%. During all tests on eastern coal, the fire in the furnace was much smokier than with western coal. An uneven bed thickness on the grate will cause the unit to smoke with eastern coal even at normal O_2 levels.


EQUALIZER
NOTCHED PLATE
SPILL PLATE
FUEL FEED RAMS
STEAM JETS
SOLID PLATE
SILL NOZZLES
ROCKER SHAFT
FUEL FEED ENGINE

FEEDER - DISTRIBUTOR

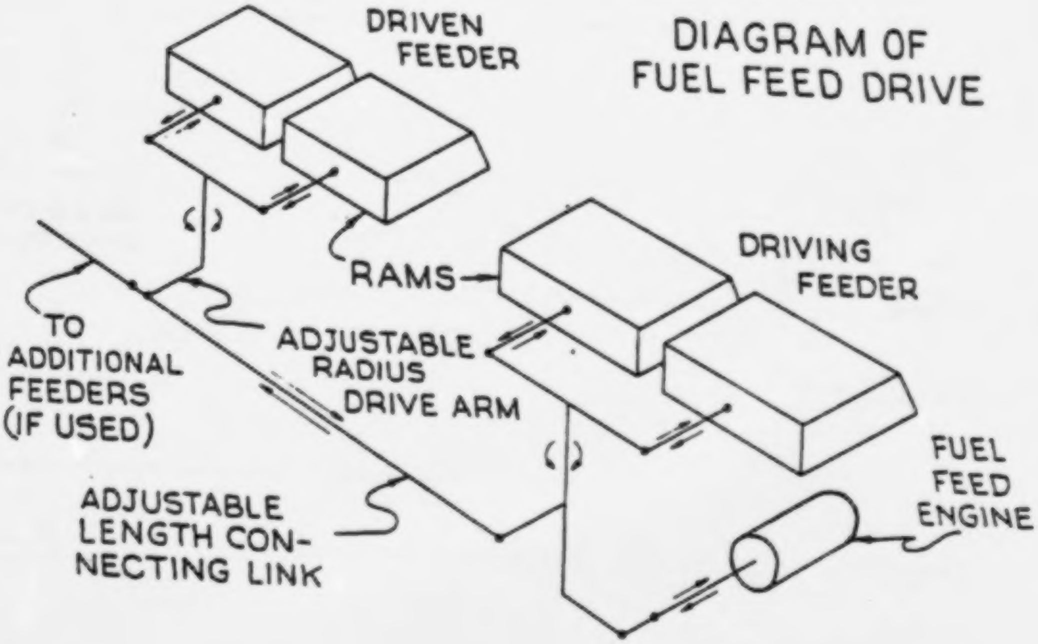


DIAGRAM OF
FUEL FEED DRIVE
DRIVEN
FEEDER
RAMS
DRIVING
FEEDER
TO
ADDITIONAL
FEEDERS
(IF USED)
ADJUSTABLE
RADIUS
DRIVE ARM
ADJUSTABLE
LENGTH CON-
NECTING LINK
FUEL
FEED
ENGINE

Figure 5.5-10. Feeder distribution and fuel feed drive.

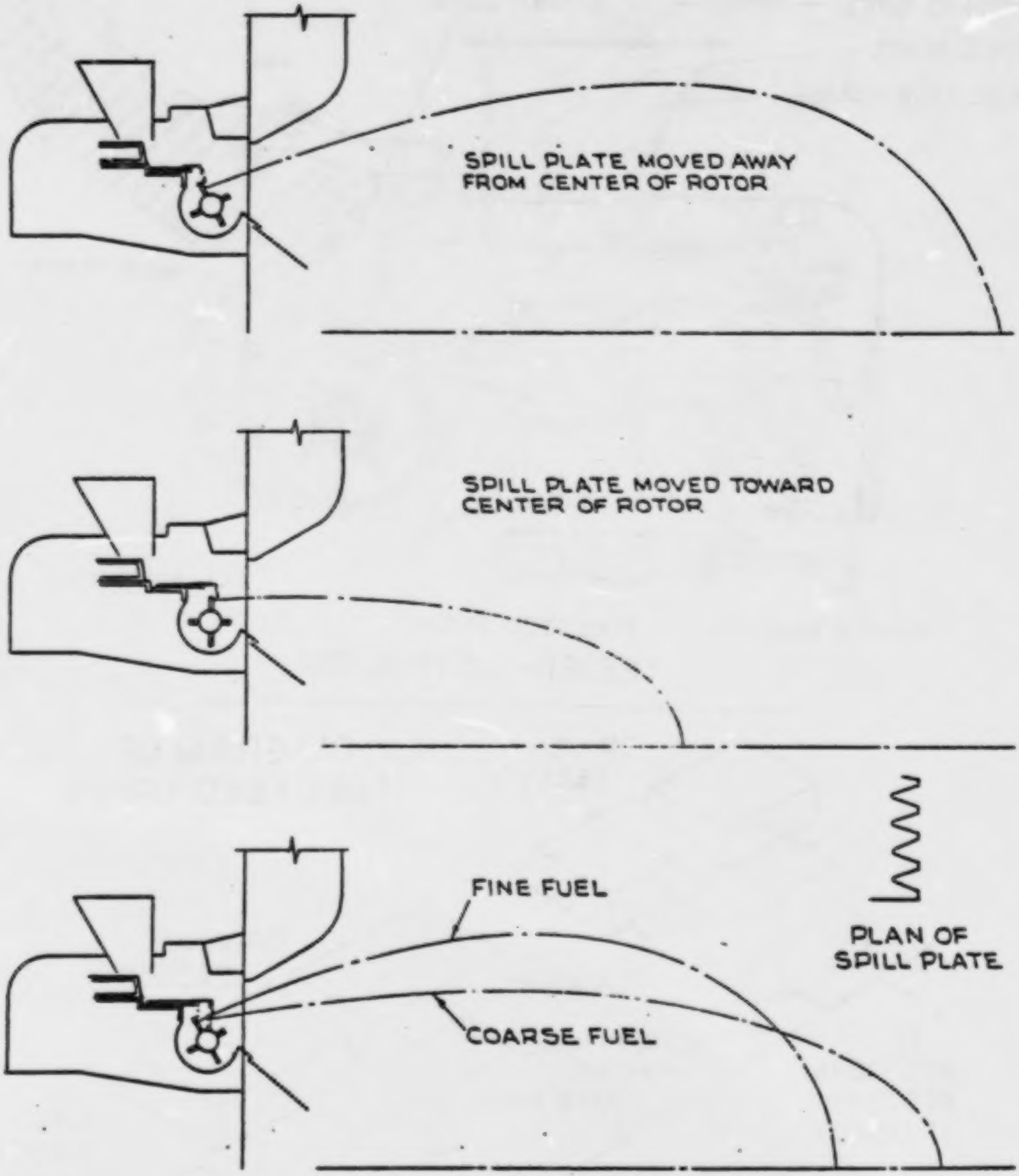

SPILL PLATE MOVED AWAY FROM CENTER OF ROTOR
SPILL PLATE MOVED TOWARD CENTER OF ROTOR
FINE FUEL
PLAN OF SPILL PLATE
COARSE FUEL

Figure 5.5-11. Effect of spill plate position.

5.5.4 Efficiency Comparison of Eastern and Western Coals

Table 5.5-3 compares boiler efficiencies while burning eastern (Test 14) and western (Tests 5 and 6) coal at the same load and excess O_2 with comparable combustible losses. The main differences in efficiency occur in the dry gas and moisture losses. The dry gas contribution is larger because of the greater amount of the lower Btu western coal that must be fired to maintain load. The moisture contribution is due to the higher moisture content of the western coal. Test 6 was at comparable boiler conditions to Tests 5 and 14 except for combustible losses which were half. Based on the averages of combustible losses for both coals in Table 5.5-1, the western coal had 40% lower losses. When this is coupled with the average 12% lower particulate emissions, combustible losses out the stack are better than 50% lower for the western coal. Thus Test 6 offers a fair comparison of unit efficiencies under typical western coal firing conditions. This comparison shows that the lower combustible losses affect the higher dry gas and moisture losses for western coal. The overall unit efficiency is unimpaired by the fuel change.

TABLE 5.5-3. COMPARISON OF BOILER EFFICIENCY ON EASTERN AND WESTERN COAL

Test No.	14 (eastern)	5 (western)	6 (western)
Test Load			
kg/s	11.3	11.3	11.3
10^3 lb/hr	90	90	90
% of Capacity	90	90	90
Stack O_2 (% Dry)	7.3	7.2	7.5
Stack CO (ppm)	1106	426	291
Stack Temp (°K/°F)	450/350	422/490	410/483
Ambient Air Temp (°K/°F)	267/20	29/272	16/264
Corr. Stack Temp (°K/°F)	450/350	422/490	410/483
Boiler Heat Bal Losses (%)			
Dry Gas	6.84	8.87	9.18
Moisture + H_2	4.92	7.91	7.88
Moisture in Air	0.17	0.21	0.22
Unburned CO	0.47	0.19	0.14
Combustibles	8.57	8.37	4.02
Radiation	0.63	0.63	0.63
Boiler Efficiency, %	78.40	73.82	77.93

The efficiency data for both eastern and western coal is contained in Table 5.5-4. These data are plotted as a function of excess O_2 in Figure 5.5-12 and as a function of load in Figure 5.5-13. At all excess O_2 levels the western coal had higher boiler efficiencies. This was due to the lower combustible losses which affect the higher dry gas and moisture losses. The efficiency as a function of load for both coals was almost the same at high and medium loads, however at low load the eastern coal efficiency was four percentage points lower than the western due to large combustible losses.

5.5.5 Conclusions

In general, the stoker at University of Wisconsin/Madison performed well on both eastern and western coals. There were no significant operational problems on either coal that would preclude their use. Maximum rated load was attained on each coal without difficulty.

From an emission standpoint, the western coal had an average of 48% lower SO_x emissions, 12% lower particulate emissions, a 40% reduction in combustible in the fly ash, and a 6% reduction in NO emissions; CO emissions were 23% higher however. The western coal could be fired at an average of 14% lower excess O_2 than the eastern coal. From a boiler efficiency standpoint, this lower excess air requirement offsets the additional moisture content of the western coal which resulted in comparable boiler efficiencies of some 78% at high load. In addition, the lower combustible losses for western coal helped improve the efficiency of western coal.

Based on fuel analyses and gaseous emissions measurements of SO_x it was calculated that on the average, the western coal emitted 99.5% of the sulfur contained in the coal whereas the eastern coal emitted 93% of the fuel sulfur.

TABLE 5.5-4. CALCULATION OF EFFICIENCY

Unit Description	
Location No.	5 (UW/Madison)
Boiler No.	2
Furnace Type	Wt
Capacity	
kg/s	12.6
10^3 lb/hr	100
MBtu/hr	113
Installed	1952
Erection Method	Field
Burner Type	SS

Western Coal Fuel Analysis (%)	
Carbon	51.09
Hydrogen	3.35
Oxygen	10.45
Nitrogen	0.78
Sulfur	0.73
H_2O	25.28
Ash	8.29
HHV/(Btu/lb)	8704
MJ/kg	20.2

Coal
Boiler Conditions

Test No.	2	3	4	5	6
Test Load					
kg/s	7.6	7.6	7.6	11.3	11.3
10^3 lb/hr	60	60	60	90	90
% of Capacity	60	60	60	90	90
Stack O_2 (% Dry)	6.5	10.9	11.4	7.2	7.5
Stack CO (ppm)	36	309	716	426	291
Stack Temp (°K/°F)	462/372	467/380	479/402	490/422	483/410
Ambient Air Temp (°K/°F)	270/26	267/24	268/22	272/29	264/16
Corr. Stack Temp (°K/°F)	462/372	467/380	479/402	490/422	483/410

Boiler Heat Balance Losses (%)
Heat Balance Losses Corrected to 300°K (80°F) Entering Air Temp

Dry Gas	7.65	11.19	12.70	8.87	9.18
Moisture + H_2	7.77	7.79	7.85	7.91	7.88
Moisture in Air	0.18	0.27	0.31	0.21	0.22
Unburned CO	0.02	0.20	0.48	0.19	0.14
Combustibles	3.12	2.63	1.92	8.37	4.02
Radiation	0.94	0.94	0.94	0.63	0.63
Boiler Efficiency, %	80.32	76.98	75.80	73.82	77.93

TABLE 5.5-4 (continued)

Unit Description

Location No.	5 (UW/Madison)
Boiler No.	2
Furnace Type	WT
Capacity	
kg/s	12.6
10^3 lb/hr	100
MBtu/hr	113
Installed	1952
Erection Method	Field
Burner Type	SS

Eastern Coal Fuel Analysis (%)

Carbon	66.32
Hydrogen	4.62
Oxygen	7.71
Nitrogen	1.30
Sulfur	3.07
H_2O	7.37
Ash	9.60
HHV/(Btu/lb)	12006
MJ/kg	27.9

Coal Boiler Conditions

Test No.	11	12	13	14	15
Test Load					
kg/s	7.6	7.6	7.6	11.3	11.3
10^3 lb/hr	60	60	60	90	90
% of Capacity	60	60	60	90	90
Stack O_2 (% Dry)	10	12	7.8	7.3	9.1
Stack CO (ppm)	29	200	0	1106	215
Stack Temp (°K/°F)	467/380	478/400	450/350	450/350	489/420
Ambient Air Temp (°K/°F)	264/16	266/18	259/6	267/20	263/15
Corr. Stack Temp (°K/°F)	467/380	478/400	450/350	450/350	489/420

Boiler Heat Balance Losses (%)
Heat Balance Losses Corrected to 300°K (80°F) Entering Air Temp

	11	12	13	14	15
Dry Gas	9.60	12.26	7.07	6.84	10.06
Moisture + H_2	4.98	5.01	4.92	4.92	5.05
Moisture in Air	0.23	0.30	0.17	0.17	0.24
Unburned CO	0.02	0.13	0	0.47	0.11
Combustibles	7.11	8.40	9.13	8.57	7.52
Radiation	0.94	0.94	0.94	0.63	0.63
Boiler Efficiency, %	77.12	72.96	77.77	78.40	76.39

TABLE 5.5-4 (continued)

Unit Description	
Location No.	5 (UW/Madison)
Boiler No.	2
Furnace Type	WT
Capacity	
kg/s	12.6
10^3 lb/hr	100
MBtu/hr	113
Installed	1952
Erection Method	Field
Burner Type	SS

Eastern Coal Fuel Analysis (%)	
Carbon	66.32
Hydrogen	4.62
Oxygen	7.71
Nitrogen	1.30
Sulfur	3.07
H_2O	7.37
Ash	9.60
HHV/(Btu/lb)	12006
MJ/kg	27.9

Coal
Boiler Conditions

Test No.	16	17	18
Test Load			
kg/s	11.3	3.8	7.6
10^3 lb/hr	90	30	60
% of Capacity	90	30	60
Stack O_2 (% Dry)	10.3	14.7	11.8
Stack CO (ppm)	236	484	13
Stack Temp (°K/°F)	494/430	444/340	467/380
Ambient Air Temp (°K/°F)	269/24	266/18	258/4
Corr. Stack Temp (°K/°F)	494/430	444/340	467/380

Boiler Heat Balance Losses (%)
Heat Balance Losses Corrected to 300°K (80°F) Entering Air Temp

	16	17	18
Dry Gas	11.43	13.54	11.40
Moisture + H_2	5.07	4.90	4.98
Moisture in Air	0.28	0.33	0.28
Unburned CO	0.13	0.44	0.01
Combustibles	7.89	11.35	7.30
Radiation	0.63	1.88	0.94
Boiler Efficiency, %	74.58	67.57	75.10

TABLE 5.5-4 (continued)

Unit Description	
Location No.	5 (UW/Madison)
Boiler No.	2
Furnace Type	Wt
Capacity	
kg/s	12.6
10^3 lb/hr	100
MBtu/hr	113
Installed	1952
Erection Method	Field
Burner Type	SS

Western Coal Fuel Analysis (%)	
Carbon	51.09
Hydrogen	3.35
Oxygen	10.45
Nitrogen	0.78
Sulfur	0.73
H_2O	25.28
Ash	8.29
HHV/(Btu/lb)	8704
MJ/kg	20.2

Coal
Boiler Conditions

Test No.	7	8	9
Test Load			
kg/s	3.8	10.1	10.1
10^3 lb/hr	30	80	80
% of Capacity	30	80	80
Stack O_2 (% Dry)	13.6	9.7	6.2
Stack CO (ppm)	1619	634	38
Stack Temp (°K/°F)	476/380	492/425	472/390
Ambient Air Temp (°K/°F)	270/26	263/14	266/19
Corr. Stack Temp (°K/°F)	467/380	492/425	472/390

Boiler Heat Balance Losses (%)
Heat Balance Losses Corrected to 300°K (80°F) Entering Air Temp

Dry Gas	15.10	11.15	7.37
Moisture + H_2	7.79	7.92	7.82
Moisture in Air	0.37	0.27	0.18
Unburned CO	1.40	0.35	0.02
Combustibles	2.03	5.84	10.01
Radiation	1.88	0.71	0.71
Boiler Efficiency, %	71.43	73.77	73.91

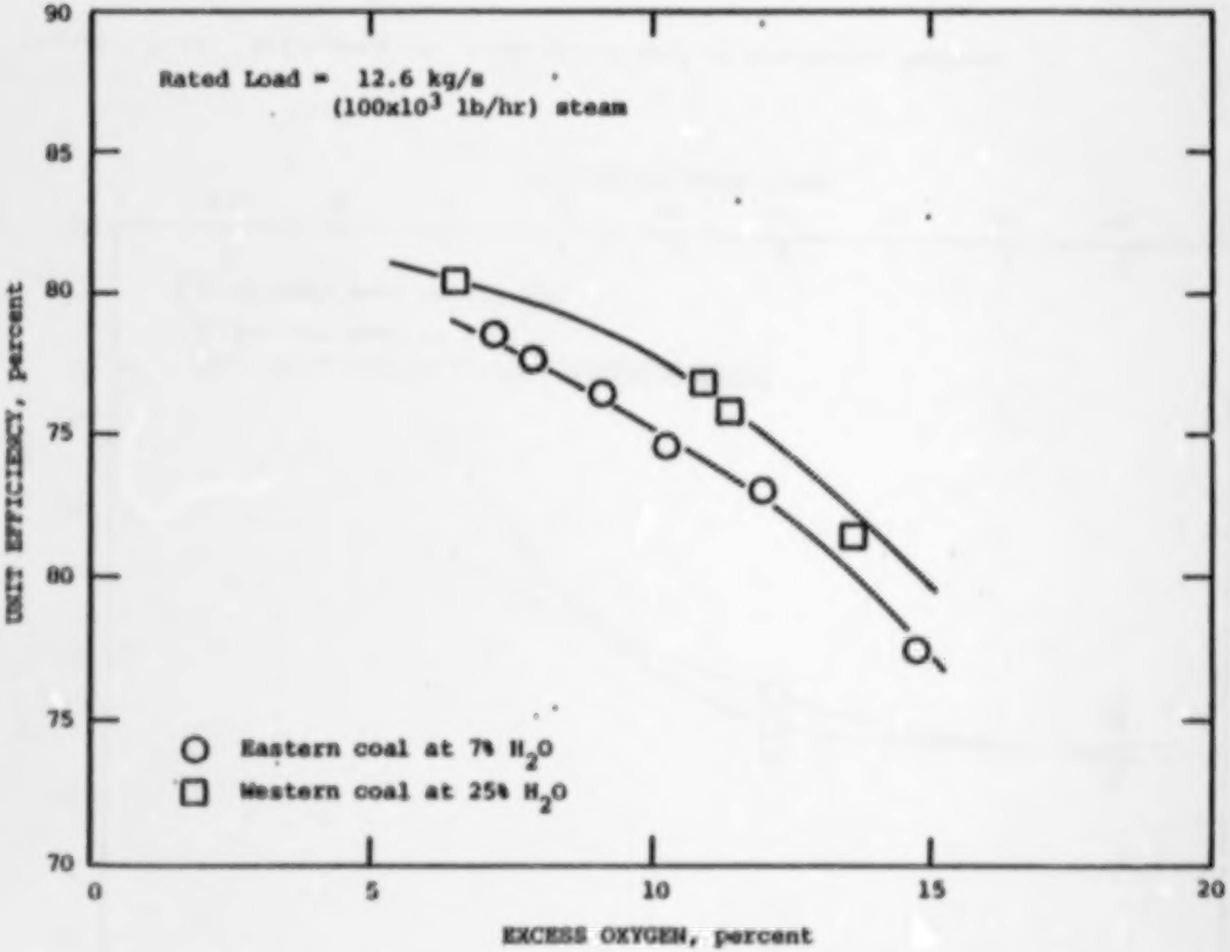


Figure 5.5-12. Boiler efficiency vs. excess O_2, University of Wisconsin, Madison.

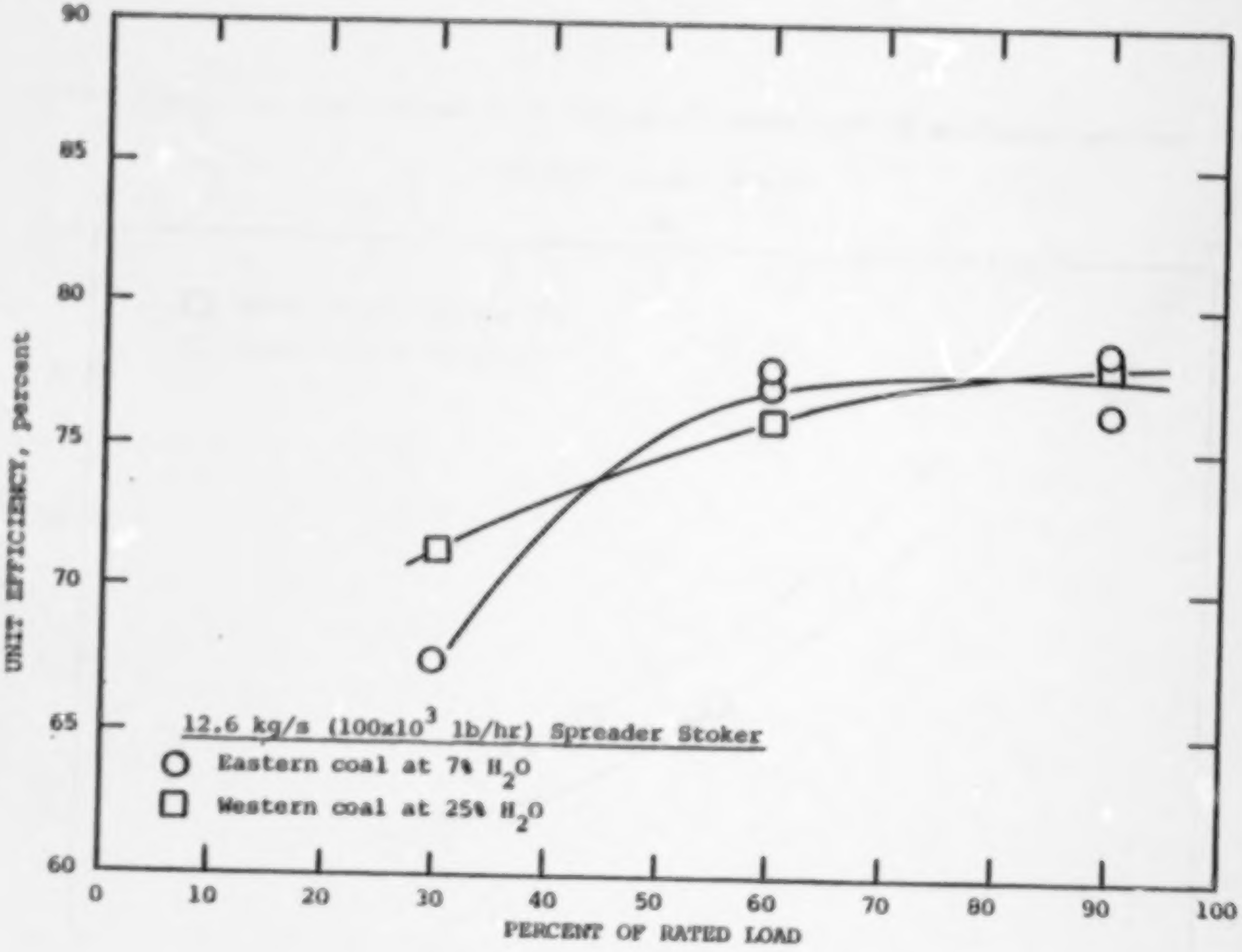


Figure 5.5-13. Efficiency vs. load, University of Wisconsin, Madison.

5.6 WILLMAR MUNICIPAL UTILITIES COMMISSION

5.6.1 Boiler Description

The fourth boiler tested was Unit #3 of the Willmar Municipal Utilities Commission located in Willmar, Minnesota. The boiler is of the two drum Stirling type built by Babcock and Wilcox in 1960. The nameplate rating for the boiler is 20.2 kg/s (160,000 lb/hr) steam flow. The unit is fired by six spreader stoker feeders supplied by the Detroit Stoker Company. They are described in the next section. The stoker is equipped with a front end discharge traveling grate. Figure 5.6-1 contains the layout and elevation of Unit #3.

The boiler is balanced draft and combustion air is supplied from underneath the grate by a forced draft fan. The undergrate air plenum is divided into two sections which are adjustable with an air damper. Grate combustion air can be biased left to right across the stoker. The negative draft of the furnace is supplied by an induced draft fan located between the air preheater and smoke stack.

The boiler has an economizer and a pendant type superheater. Combustion air is preheated by a tubular type air preheater located between the induced draft fan and the dust collector. The air preheater was found to be defective during testing, this caused a fraction of the incoming air to be "short circuited" through the air heater and out the stack.

Fly ash is removed with a Western Precipitator Multiclone dust collector. This mechanical type cyclone dust collector is located between the economizer and the air heater. The steam produced is superheated and used both for electrical power generation and for direct heating. The following data applies to this unit:

- Based on 27.9 MJ/kg (12,000 Btu/lb) Southern Illinois coal (April 1961)
  - Maximum continuous steam output - 20.2 kg/s (160,000 lb/hr)
  - Efficiency - 87.78%

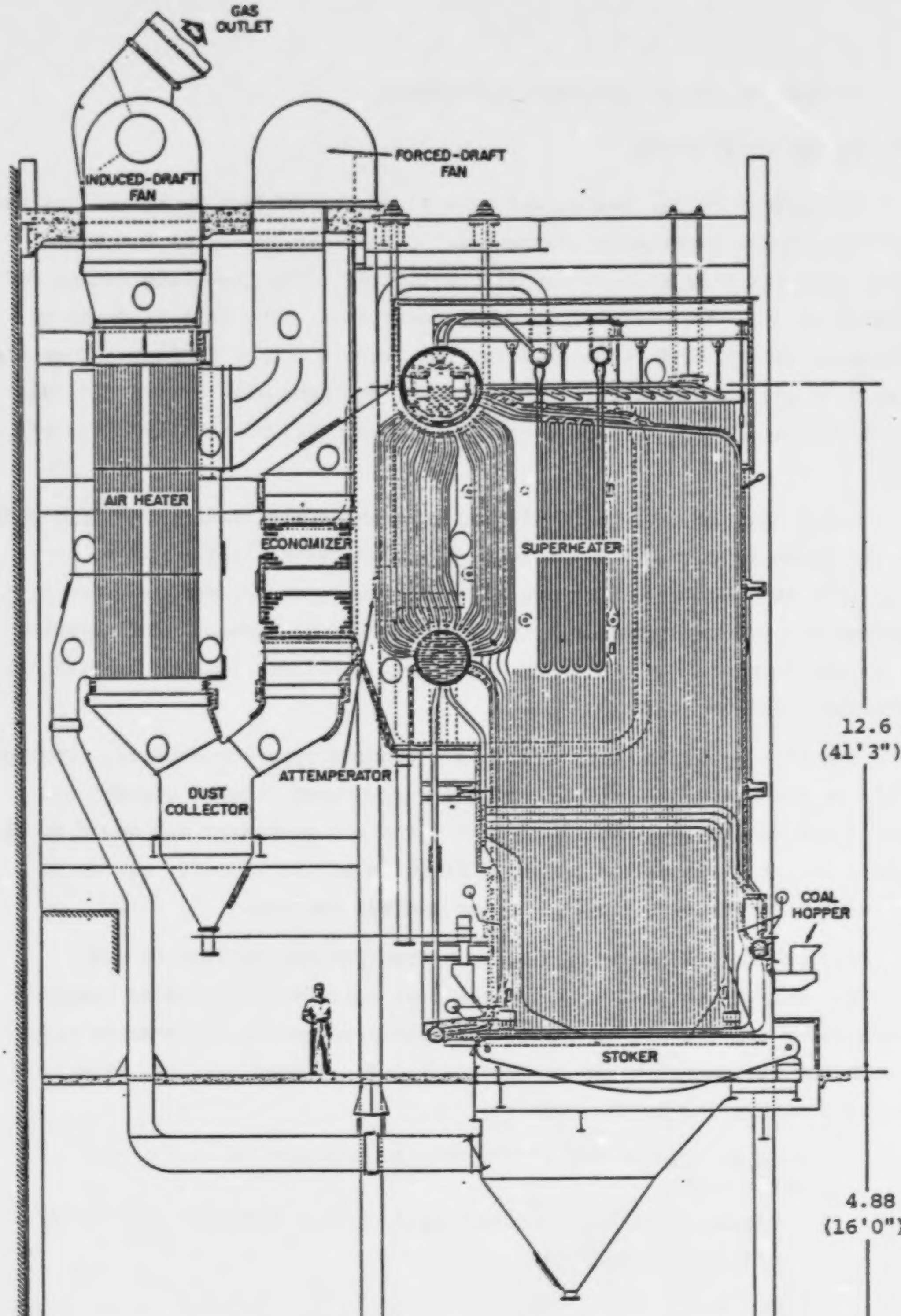

GAS OUTLET
INDUCED-DRAFT FAN
FORCED-DRAFT FAN
AIR HEATER
ECONOMIZER
SUPERHEATER
DUST COLLECTOR
ATTEMPERATOR
COAL HOPPER
STOKER
12.6 m
(41'3")
4.88 m
(16'0")
6.02 m
(19'9")
7.01 m
(23'0")

Figure 5.6-1. Unit 3, Willmar Municipal Utilities Commission, Willmar, Minnesota.

- Based on 19.2 MJ/kg (8,240 Btu/lb) Montana coal (December 1972)
  - Maximum continuous steam output - 16.4 kg/s (130,000 lb/hr)
  - Efficiency - 82.63%
- Steam conditions at superheater outlet
  - Temperature - 672 °K (750 °F)
  - Pressure - 2.9 MPa (425 psi)
  - Design Pressure - 6.8 MPa (1000 psi)
- Heating Surfaces
  - Boiler - $1.316x10^3$ m^2 (14,168 ft^2)
  - Water Wall - $20x10^2$ m^2 (2,158 ft^2)
  - Superheater, primary - $3.5x10^2$ m^2 (3,778 ft^2)
  - Superheater, secondary - $1.61x10^2$ m^2 (1,731 ft^2)
  - Economizer - $3.95x10^2$ m^2 (4,250 ft^2)
  - Air heater - $1.21x10^3$ m^2 (13,030 ft^2)

5.6.2 Stoker Description

Willmar Boiler #3 is fired by a Detroit Stoker Company Rotograte spreader stoker. Figure 5.6-1 includes a side view of the stoker. This stoker is fired by six individual feeders. Raw coal leaves the bunker and is weighed by two coal scales as the coal is divided into a left and a right feed stream. After the coal scales (left and right), the coal enters left and right coal distributors. Each distributor supplies raw coal to three feeders. From the distributor, coal enters each stoker feeder.

Each feeder can be independently adjusted to distribute coal on the grate. Three mechanisms give this control. First, is a spill plate adjustment which regulates the point at which coal is dropped onto the rotating paddle wheel. The second, is the length of stroke of the feed plate which pushes the coal over the spill plate. The third, is the rotor speed. Additionally, the fuel bed thickness can be controlled by the speed of the traveling grate.

5.6.3 Sampling Locations

Willmar Unit #3 is equipped with a Western Precipitator Multiclone cyclone type dust collector. Sampling sites were selected such that inlet and outlet data and emission characteristics were obtained for the collection device. The inlet sampling plane, located just upstream of the cyclone in the inlet breaching, was the only area available to obtain inlet data due to the duct configuration of the boiler. Figure 5.6-2 presents a cross sectional diagram of the inlet sampling site. This site was somewhat unsuitable for particulate measurements due to its nearness to an upstream bend in the ducting. Some of the inlet particulate data is questionable, however the gaseous data is accurate. Figure 5.6-3 presents the cross sectional view of the inlet sampling probe locations. The duct was wide but narrow. Twelve probes were installed for gaseous emission testing and of these twelve stainless steel probes, six were equipped to measure hot line data. The twelve probes were installed in six ports, two in each port. Twelve 3/8 inch diameter type-T nylon sample lines connected the sample probes to the mobile test lab. Sampling took place during the middle of winter in the cold prairie section of Minnesota. The sections of sample lines that were outside the building were insulated with fiberglass insulation and wrapped with a pipe heating tape. The entire sample line bundle was covered with a waterproof plastic liner to protect it from moisture.

An existing location in a section of breeching between the ID fan and chimney was used for the outlet sample site (Fig. 5.6-4). This location had been used for previous State of Minnesota Pollution Control Agency compliance tests. Four ports were located at the site. Three probes were installed into each port at the centroids of equal areas for a total of twelve sample probes. This sample site was outside and special insulating material and heating tapes were required to keep the nylon sample lines from freezing during the cold winter weather.

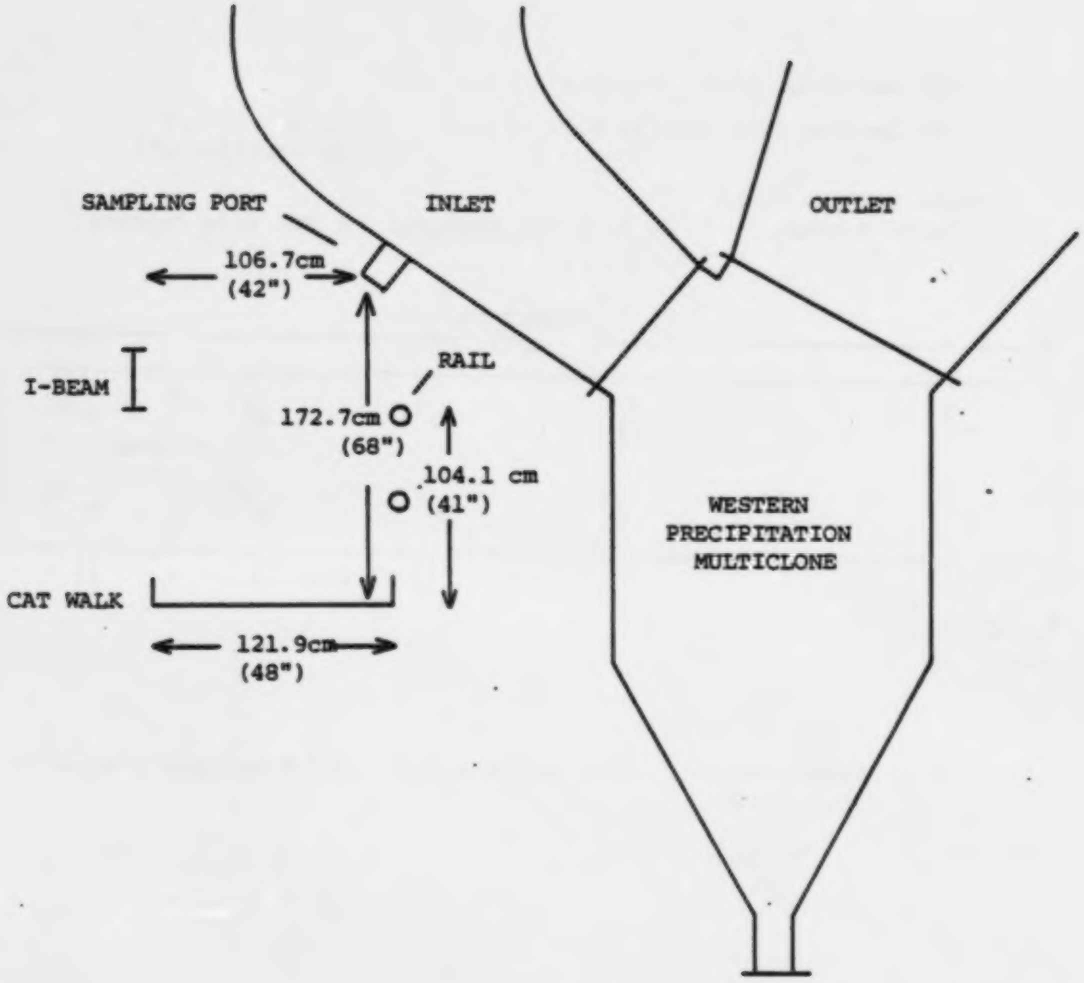

SAMPLING PORT
INLET
OUTLET
106.7cm
(42")
I-BEAM
RAIL
172.7cm
(68")
104.1 cm
(41")
WESTERN
PRECIPITATION
MULTICLONE
CAT WALK
121.9cm
(48")

Figure 5.6-2. Side view, inlet sampling area.

Cross Sectional Area: 6.039 m^2 (65.0 ft^2)

Probe Lengths from Outside Edge of Port: 43.34 cm (17-3/4"),
93.98 cm (37-1/4")

Probe Numbers Shown
Probe Numbers 1, 4, 5, 8, 9, 12 equipped for Hot Line Testing

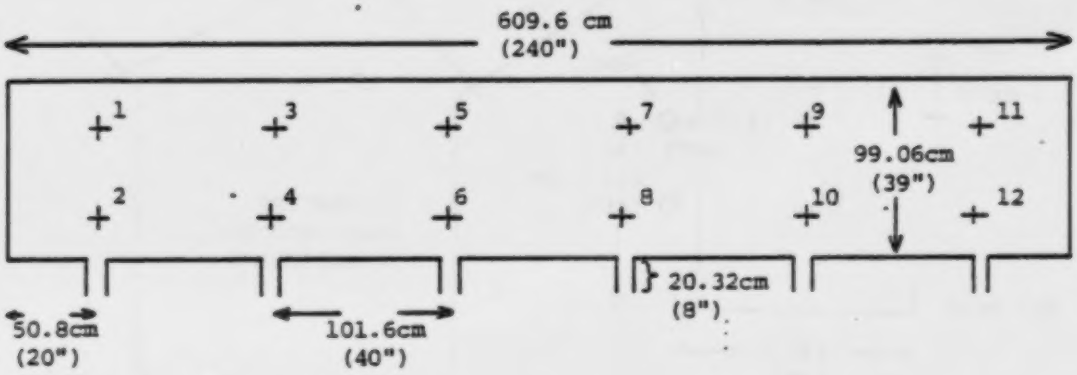

609.6 cm
(240")
1
2
3
4
5
6
7
8
9
10
11
12
99.06cm
(39")
20.32cm
(8")
50.8cm
(20")
101.6cm
(40")

Figure 5.6-3. Cross section, inlet sampling duct, top view, gas flow is into paper.

Cross Sectional Area: 2.016 m^2 (21.7 ft^2)

Probe Lengths From Outside Edge of Port: 35.56 cm (14-1/8"), 76.2 cm (30-3/8"), 16.8 cm (46-5/8")

Probe Numbers Shown

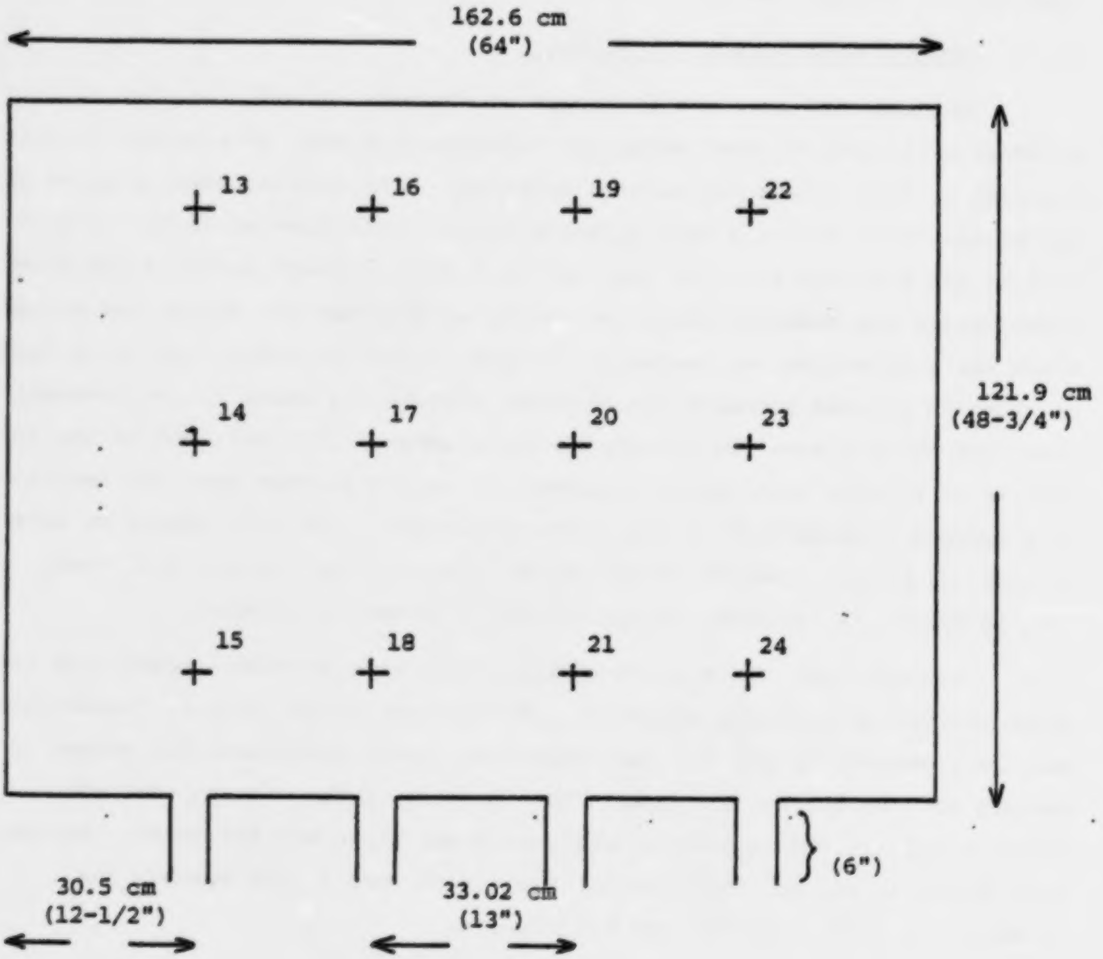

162.6 cm
(64")
13
16
19
22
14
17
20
23
15
18
21
24
121.9 cm
(48-3/4")
(6")
30.5 cm
(12-1/2")
33.02 cm
(13")

Figure 5.6-4. Cross section, outlet sampling duct, top view, gas flow is out of paper.

5.6.4 Comparison of Test Coals

Willmar Unit #3 normally burns a western type fuel, because the utility had trouble in obtaining a reliable supply of eastern coals. Several years ago so they switched to the more dependable western coal supplier. The western coal burned during these tests was a Montana coal from Colstrip, Montana. For the test series a special order of eastern type coal was obtained. This fuel was from the Sahara mine in Southern Illinois. Analyses of the two test fuels are presented in Table 2-1. As with most western subbituminous coals the Colstrip coal had a high moisture content, high volatile and low fixed carbon content and moderate sulfur content.

5.6.5 Western Coal Burning at Willmar

Montana coal is normally burned at Willmar. A small penalty is paid in total unit capacity when using the subbituminous coal in a stoker originally designed to fire a high Btu eastern type coal. The maximum load obtained with the Montana coal was 16.1 kg/s (128,000 lb/hr) steam flow while the maximum load on the Southern Illinois fuel was 16.8 kg/s (133,400 lb/hr) steam flow. These values are somewhat deceptive since, at the time the boiler was tested, there was a defective air heater in service. This air heater had large leaks in it which allowed incoming air to short circuit its route to the combustion zone, and hence starve the undergrate air chamber. This resulted in the unit smoking at a lower than normal maximum load on the eastern coal and resulting in a reduced maximum load at the given conditions. The unit should be able to make 20.2 kg/s (160,000 lb/hr) steam flow with the eastern coal when the air heater is repaired and the stoker is properly adjusted.

Western coal can be successfully fired on a spreader stoker with only minor changes in existing equipment. For a given boiler output, feeder rates must be increased to get the same amount of energy input into the stoker on western coal as for eastern coal. The fineness of the western coal ash requires thicker bed to prevent ash from being blown off the grate. Willmar Unit #3 ran an ash bed thickness of 5 to 10 cm when firing western fuel. Feeder rates were increased about 10 to 15%.

Higher superheat temperatures were encountered with the higher moisture western coals. Willmar Unit #3 was equipped with a through-the-mud drum type steam attemperator. This device was used when firing western coal to control the superheat temperature. No control read-outs were available to measure the absolute percentage of steam by-passed into the attemperator but the controller which controlled the bypass valve was set at about 50% for Montana coal. Increasing the overfire air can reduce the CO emissions somewhat; but, the unit did not operate in that mode as a normal operating procedure. A short series of tests ran overfire air pressure from normal as-found settings of 7.5 - 8.5 inches H_2O to the maximum setting, and corresponding CO emissions of 181 ppm at 3.0% excess O_2 were reduced to 140 ppm at 3.0% excess O_2. Nitric oxide emissions did not vary significantly with the change in overfire air.

There was no appreciable flame impingement on the furnace side walls or back walls with western coal firing. The fuel bed was uniform and well established. The coal combustion on the grate was nonswelling and nonagglomerating. Coke pieces tended to retain their individual size and identity when burning on the grate. The main flame front began about four feet from the vertical plane of the feeders for western coal burning. No clinkers were formed while burning western coal. There were "sparklers" or suspension burning with the western coal. These sparklers were carried up into the superheat pendant section.

Moderate slagging occurred in the superheat pendant tube section. Slag deposits of two to four inches in thickness covered the pendant loops about 1/2 to 2/3 up the tubes. There was some flame impingement on these areas. Some slag build-up was sufficient to cause bridging of formations between pendants, however it was not of sufficient quantity as to cause flow restriction through the superheater.

Generally the Montana coal performed well on the stoker. Except for the reduced load, the coal was a better fuel than the eastern coal which clinkered and had a serious smoking problem.

5.6.6 Emissions Data

A. Sulfur Oxides--

Table 5.6-1 contains a summary of all emission tests conducted at Willmar on both eastern and western coal. In all, thirty-four tests were run (fourteen on eastern coal and twenty on western coal). Sulfur oxides emissions from western coal were about half that of eastern coal. The average SO_2 emissions from the eastern coal were 1489 ng/J (3.47 $lb/10^6$ Btu) compared to 766 ng/J (1.79 $lb/10^6$ Btu). The Colstrip coal tested on this unit exhibited the greatest sulfur retention of any coal tested with an average of only 65% of the fuel sulfur emitted in the flue gas. This number compares to a fuel sulfur emissions of 94% on eastern coal on this same unit.

The SO_2 emissions from either the western or the eastern coal did not follow a trend with either load or excess air. The SO_3 component of the SOx emission was generally less than 3 percent of the total. Neither the amount of SO_3 nor the ratio of SO_3/SOx exhibited a definable trend with any of the test variables.

B. Particulates--

The uncontrolled particulate loadings were found to exceed the ash content of the fuel by as much as a factor of four. Even when the carbon content of the ash was taken into account, these figures could not be reconciled with the uncontrolled particulate loadings. Therefore the error must be with the sampling location described above.

Controlled particulate loading were within reasonable limits of 166-545 ng/J (0.39 - 1.27 $lb/10^6$ Btu). The overall average particulate loading of all the tests for eastern and western coal are shown in Table 5.6-1. The average western coal emission was some 24% less than the average for eastern coal. The carbon content of the western coal fly ash was also 33% less than that from the eastern coal. The particulate emissions followed no definable

TABLE 5.6-1. EMISSION SUMMARY, WILLMAR UNIT 3

Test No.	Date	Load kg/s (10^3 lb/hr)	Conditions	SO_2 Meter 3% O_2 ppm	CYCLONE INLET				CYCLONE OUTLET						Part ng/J (#/MBtu) Out	SOx ppm	Notes
					O_2, %	CO ppm 3% O_2	CO_2 %	NO ppm 3% O_2	O_2, %	CO ppm 3% O_2	CO_2 %	NO ppm 3% O_2	kg Steam / kg Coal	% C in Ash			
EASTERN COAL																	
21	1/15/75	13.5 (107.4)	Normal O_2, Med. Load	OOS	8.59	314	9.15	447	9.0	188	8.8	495	8.2	--	--	1643	Prelim. Unit Check Out
22	1/19	14.1 (112.0)	Normal O_2, Med. Load	OOS	8.22	369	9.74	471	8.65	351	9.4	445	8.6	--	--	1534	
23	1/20	22.8 (114.5)	Normal O_2, Med. Load	OOS	8.17	146	9.9	491	9.13	367	8.9	439	8.7	26.8	316 (0.7355)	--	Part In and Out
24	1/21	14.1 (111.7)	Normal O_2, Med. Load	OOS	8.38	368	9.67	514	8.6	1306	8.8	515	8.6	--	--	1462 1589	SOx In SOx Out
25	1/22	13.3 (105.4)	High O_2, Med. Load Spill Plate Reset	1798	9.43	44	9.03	491	11.0	20	8.4	502	8.6	25.8	371 (0.8622)	--	Part In and Out
26	1/23	13.3 (105.5)	High O_2, Med. Load In Out	1795 1712	8.56	39	9.16	532	8.7	44	8.8	520	8.7	--	--	2067	SOx Inlet
27	1/26	15.6 (124.0)	Normal O_2, High Load	OOS	6.62	289	11.13	415		PROBE			8.4	--	--	1849	SOx Inlet
28	1/27	15.8 (125.4)	Normal O_2, High Load	OOS	6.45	509	11.24	395	7.4	520	10.6	293	8.3	26.9	294 (0.6834)	1721	SOx Inlet
29	1/28	11.4 (91.0)	Normal O_2, Low-Med. Load	OOS	7.42	113	10.54	366		PROBE			8.9	--	--	--	Gaseous Only
30	1/30	10.5 (83.5)	Normal O_2, Low Load	OOS	9.95	51	8.55	441	10.7	58	7.88	432	8.5	25.9	350 (0.8135)	1651	Part In and Out; SOx In
31	1/31	9.6 (76.1)	Low O_2, Low Load	OOS	8.38	26	9.91	341		PROBE		--	8.1	28.4	264 (0.6131)	1788	Part In and Out; SOx In
32	2/1	11.0 (87.3)	High O_2, Low Load	OOS	11.92	84	7.38	492	12.3	90	7.4	481	8.5	26.8	545 (1.2670)	1792	Part In and Out; SOx In
33	2/2	13.8 (109.8)	Low O_2, Med. Load	OOS	6.63	89	11.08	375	--	--	--	--	8.7	28.0	234 (0.5443)	1778	Part In and Out; SOx In
34	2/5	16.8 (133.4)	Max. Cont. Load, Post O.S. Boiler Tune Up	--	5.05	216	11.7	336	7.2	205	10.9	326	8.67	28.0	320 (0.7650)	1815	Part In and Out; SOx In
Average		13.4 (106.2)			8.18	190	9.87	436	9.27	315	8.99	445	8.53	27	338 (0.7855)	1724	

(continued)

TABLE 5.6-1 (continued).

Test No.	Date	Load kg/s (10^3 lb/hr)	Conditions	SO_2 Meter 3% O_2 ppm	CYCLONE INLET				CYCLONE OUTLET						Part mg/J (#/MBtu) Out	SOx ppm	Notes
					O_2, %	CO ppm 3% O_2	CO_2 %	NO ppm 3% O_2	O_2, %	CO ppm 3% O_2	CO_2 %	NO ppm 3% O_2	kg Steam / kg Coal	% C in Ash			
WESTERN COAL																	
1	12/2/75	13.5 (107)	Normal O_2, Normal Operation	972	7.8	540	10.3	363	--	--	--	--	5.65	--	--	867	SOx Out
2	12/3	14.1 (112)	Normal O_2, Normal Operation	827	7.3	880	10.4	387	--	--	--	--	5.80	--	--	785	SOx In
3	12/4	12.3 (97.5)	Normal O_2, Normal Operation	793	7.9	527	10.1	389	--	--	--	--	5.81	19.1	$\frac{10,956}{325}$ $\left(\frac{25.48}{0.7551}\right)$	--	Part In Part Out
4	12/5	13.0 (103)	Normal O_2, Normal Operation	776	7.6	800	10.4	398	8.6	466	10.1	407	5.86	--	--	851	Meter Outlet
5A	12/8	13.2 (105)	Vary Overfire Air (OFA) As Found	1126	9.3	463	9.1	366	--	--	--	--	5.72	--	--	--	
5B	12/8	13.2 (105)	Vary OFA - Increase Air	955	9.5	136	9.0	363	--	--	--	--	5.72	--	--	--	
5C	12/8	13.2 (105)	Vary OFA - Further Increase Air	920	7.5	145	10.9	356	--	--	--	--	5.72	--	--	--	
5D	12/8	13.2 (105)	Vary OFA - Return to Normal	945	8.2	181	10.5	333	--	--	--	--	5.72	--	--	--	
6A	12/9	13.8 (109.5)	Vary OFA - Bias Top Row	978	7.7	378	10.4	333	--	--	--	--	7.72	--	--	--	
6B	12/9	13.8 (109.5)	Vary OFA - As Found	--	7.3	237	10.9	355	--	--	--	--	7.52	--	--	--	
6C	12/9	13.8 (109.5)	Vary OFA - Bias Top Row	--	7.2	313	10.9	352	8.1	209	10.2	412	7.52	--	--	859	Meter Out
7	12/10	12.9 (102)	Vary Grate Air, Normal O_2	980	7.5	176	10.5	355	8.2	227	10.3	362	6.49	--	--	1020	Meter Out
8	12/11	13.7 (108.5)	Max. O_2, Normal Operation In Out	915 1091	8.6	332	9.7	427	9.1	326	9.4	439	5.75	19.9	$\frac{18,146}{303}$ $\left(\frac{42.197}{0.7054}\right)$	934	Part In and Out; SOx In
9A	12/12	14.6 (111)	Vary Grate Air - As Found	880	7.4	280	10.6	392	--	--	--	--	5.8	--	--	--	
9B	12/12	14.0 (111)	Vary Grate Air - West Throttle, East Open	875	7.3	337	10.6	369	--	--	--	--	5.8	--	--	--	

(continued)

TABLE 5.6-1 (continued).

Test No.	Date	Load kg/s (10^3 lb/hr)	Conditions	SO_2 Meter 3% O_2 ppm	CYCLONE INLET				CYCLONE OUTLET						Part ng/J (#/MBtu) Out	SOx ppm	Notes
					O_2, %	CO ppm 3% O_2	CO_2 %	NO ppm 3% O_2	O_2, %	CO ppm 3% O_2	CO_2 %	NO ppm 3% O_2	kg Steam / kg Coal	% C in Ash			
WESTERN COAL - Continued																	
10	12/16/75	9.1 (72)	Normal O_2, Low Load	1020	9.5	262	9.4	338	--	--	--	--	5.73	12.2	$\frac{8,038}{186}$ $\left(\frac{18.67}{0.4315}\right)$	--	Part In and Out
11	12/17	10.4 (83)	Normal O_2, Low Load	1129	8.6	143	9.8	366	--	--	--	--	5.82	--	--	1146	SOx In
12	12/18	10.4 (82)	High O_2, Low Load	712	10.6	165	9.3	370	--	--	--	--	5.63	--	--	846	SOx In
13	12/19	10.2 (80)	High O_2, Low Load	770	9.9	198	9.0	382	--	--	--	--	5.70	13.3	$\frac{8,080}{290}$ $\left(\frac{18.79}{0.6754}\right)$	--	Part In and Out
14	12/20	9.9 (79)	Low O_2, Low Load	664	7.7	129	10.5	304	8.6	111	10.0	307	OOS	15.0	$\frac{5,802}{166}$ $\left(\frac{13.499}{0.3867}\right)$	--	Part In and Out
15	12/22	9.9 (79)	Low-Med. O_2, Low Load	726	8.2	236	10.4	344	--	--	--	--	5.72	--	--	815	SOx In
16	1/6/76	14.0 (111)	Low-Med. O_2, Low Load	937	6.6	1182	11.6	324	--	--	--	--	5.75	21.9	$\frac{4,657}{277}$ $\left(\frac{10.83}{0.6432}\right)$	849	Part In and Out; SOx In
17	1/7	15.9 (126)	Normal O_2, Maximum Load	1057	6.7	642	11.4	366	--	--	--	--	5.68	--	--	932	SOx In
18	1/8	16.1 (128)	Normal O_2, Maximum Load	963	6.0	2200	11.9	315	--	--	--	--	5.59	25.5	$\frac{12,236}{258}$ $\left(\frac{28.45}{0.6001}\right)$	--	Part In and Out
19	1/12	14.2 (113)	Low O_2, Medium Load	OOS	6.8	1221	11.4	363	7.85	876	11.4	356	5.58	--	--	870	SOx Out
20	1/13	14.5 (115)	Normal O_2, Medium Load	OOS	6.9	1003	OOS	374	8.3	1032	11.0	350	5.61	--	--	--	Complete Inlet and Outlet Gaseous
Average		13.6 (107.6)			7.9	504	10.36	359	8.39	667	10.34	376	5.98	18.14	258 (0.5996)	899	

trend with either boiler load or flue gas excess O_2. Indicated cyclone collection efficiencies were very high due to the questionable inlet particulate loadings. Assuming a cyclone efficiency of 85% one can back-calculate the inlet particulate loading of about 2252 ng/J (5.3 lb/10^6 Btu) which is a factor of 4 to 5 lower than the measured loading. Therefore the measured inlet loadings are considered to be unreliable. The problem is thought to be the sampling location rather than any procedural error in the sampling technique.

C. Nitric Oxide--

Nitric oxide (NO) emissions measurements are given in Table 5.6-1 for both coals. The overall average emission of NO was reduced approximately 18% by switching to western coal. Figures 5.6-5 and 5.6-6 contain the nitric oxide vs. O_2 data for Montana and Illinois coal respectively. Both data sets are at a medium load and both exhibit the expected trend of increasing NO with increasing excess O_2. The NO emissions from the Montana coal are all about 50 ppm lower than the NO emissions from the Illinois coal. This difference may be a result of differing fuel nitrogen content (Ill. = 1.35% fuel N, and Mont. = 0.68% fuel N) of the two coals; or it may be due to the high moisture content of the Montana coal which affects the combustion intensity (flame temperature) resulting in lower thermal fixation. The nitric oxide emissions were relatively constant with load for both coals.

D. Carbon monoxide and Carbon Carryover--

The characteristic carbon monoxide emissions are given for Montana and Illinois coals in Figures 5.6-7 and 5.6-8 respectively. Both coals exhibit increasing CO emissions with increasing load. The quenching of the CO combustion is more extensive on Montana coal than on the Illinois coal. It has been demonstrated on other units, as well as this one, that CO emissions can be controlled by increasing the excess air. Inspection of the data in Table 5.6-1 shows that when the excess O_2 is lowered to 6%, the CO emissions become significant. Comparing Tests 17 and 18, at the same load, demonstrated that increasing the excess O_2 by 0.7% reduced the CO from 2200 ppm to 642 ppm.

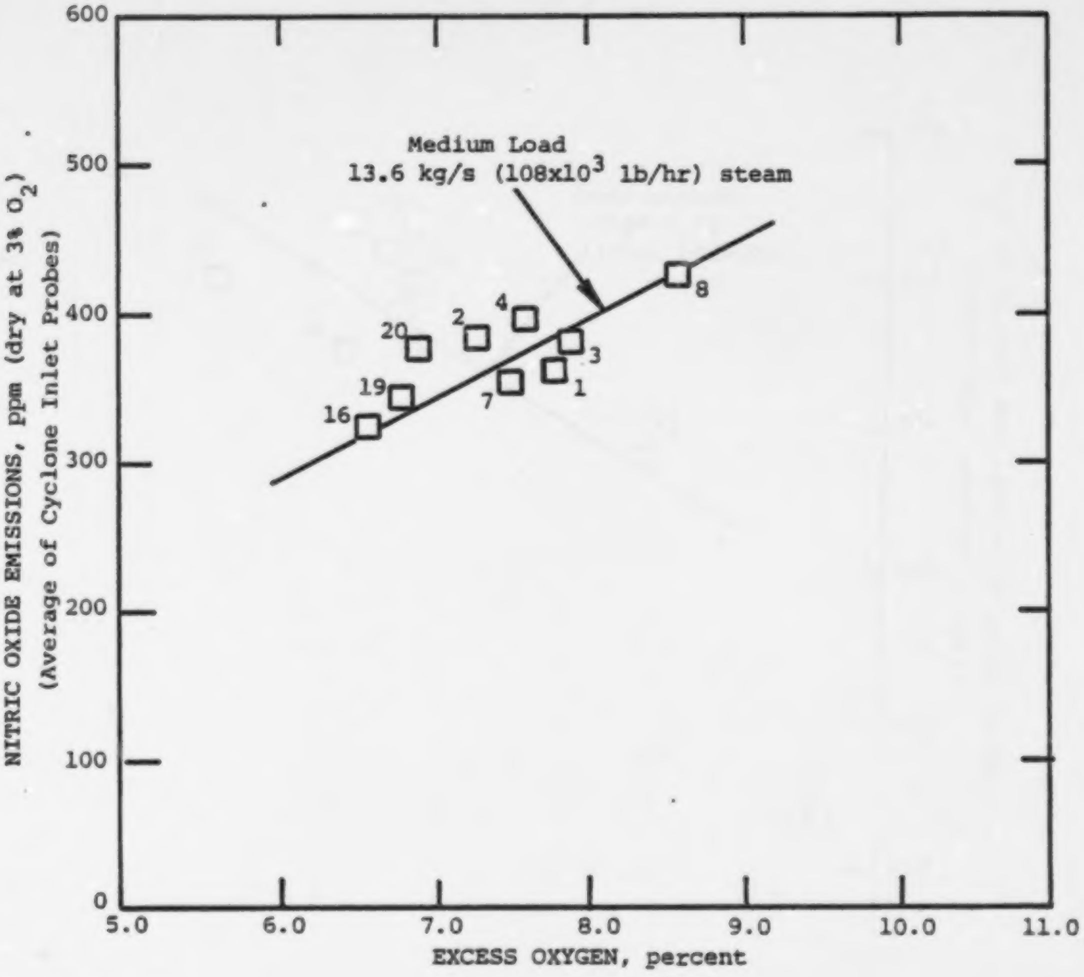


Figure 5.6-5. Nitric oxide vs. excess oxygen, Willmar Unit 3, western coal.

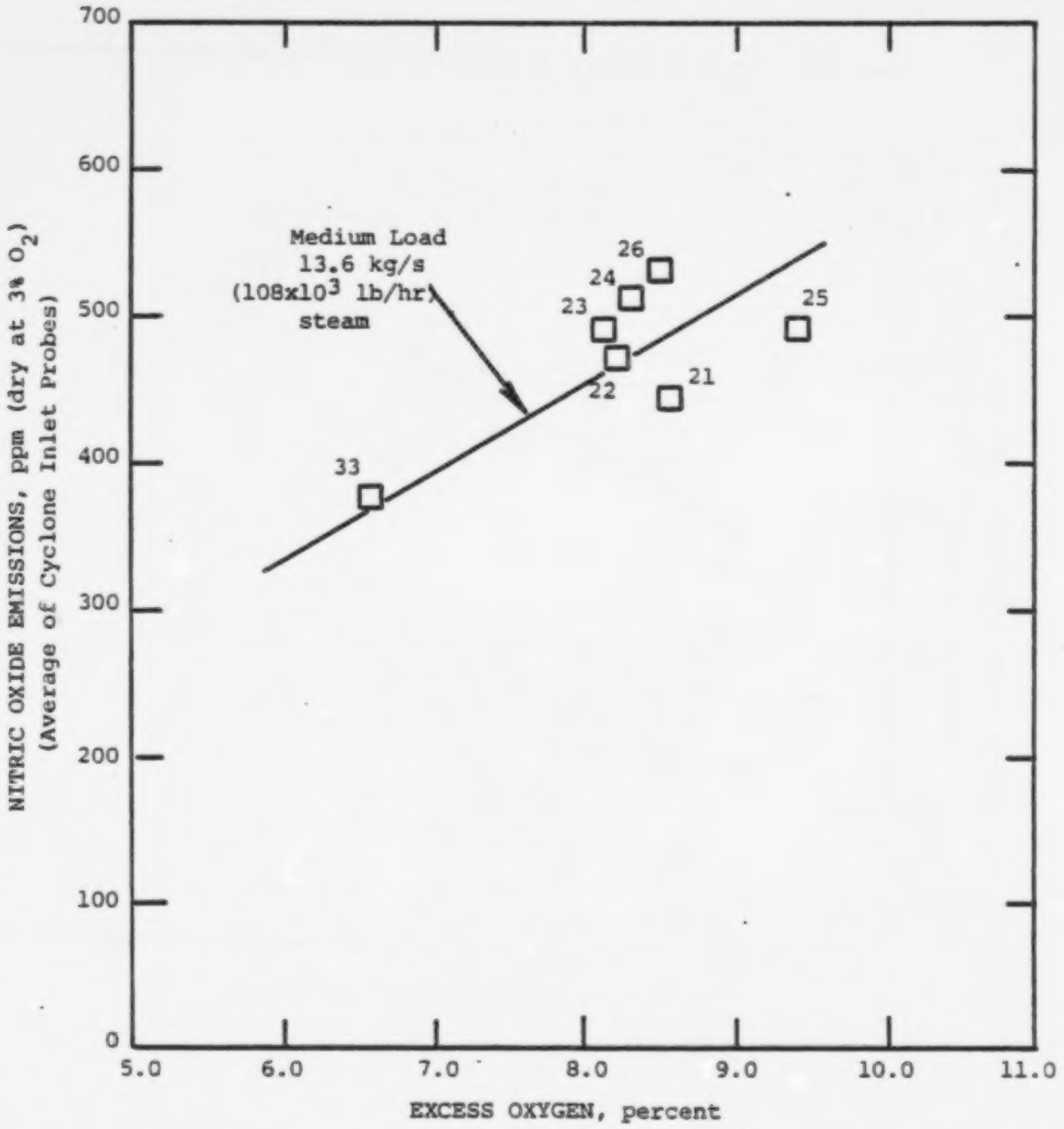


Figure 5.6-6. Nitric oxide vs. excess oxygen, Willmar Unit 3, eastern coal.

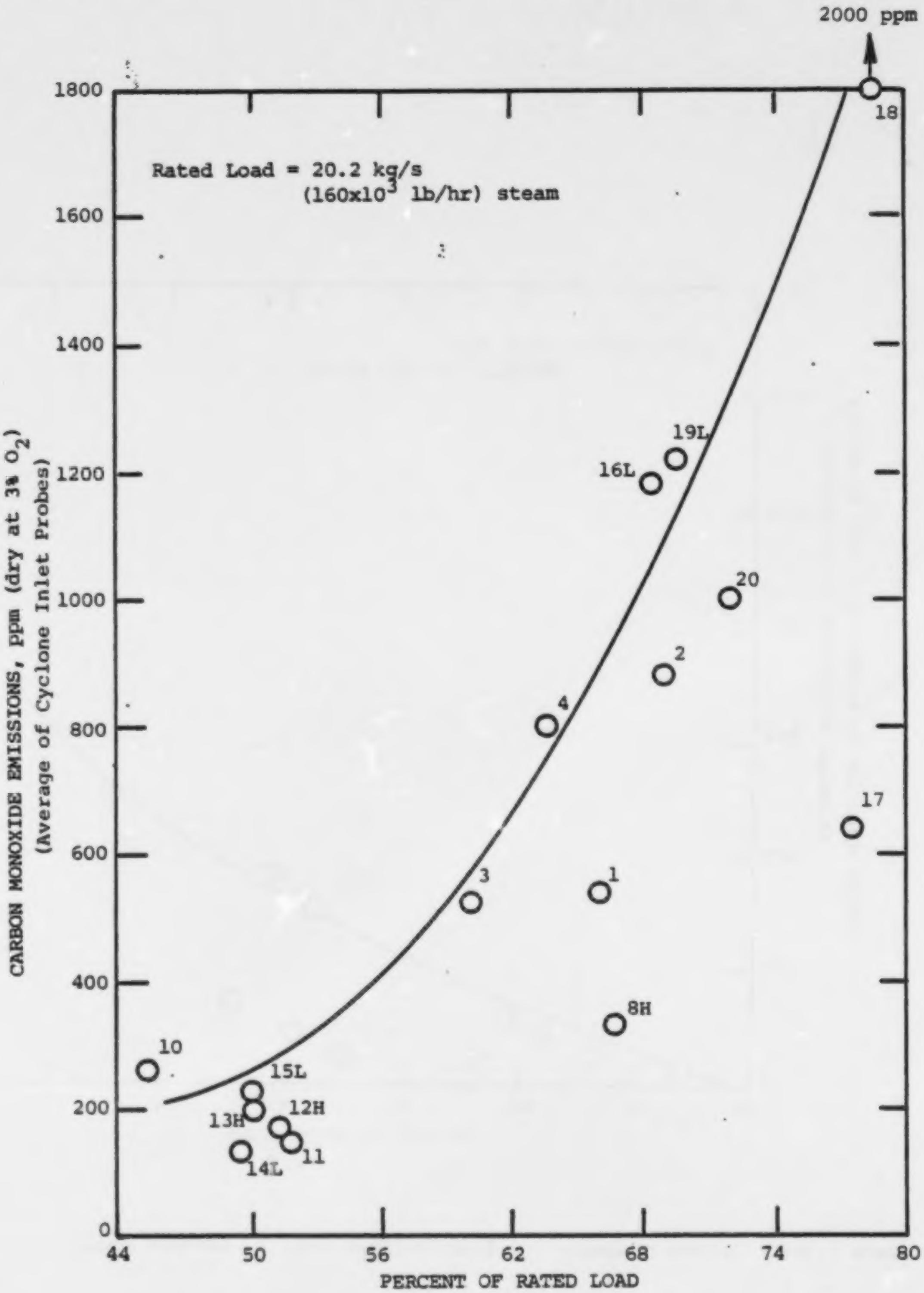


Figure 5.6-7. Carbon monoxide vs. load, Willmar Unit 3, western coal.

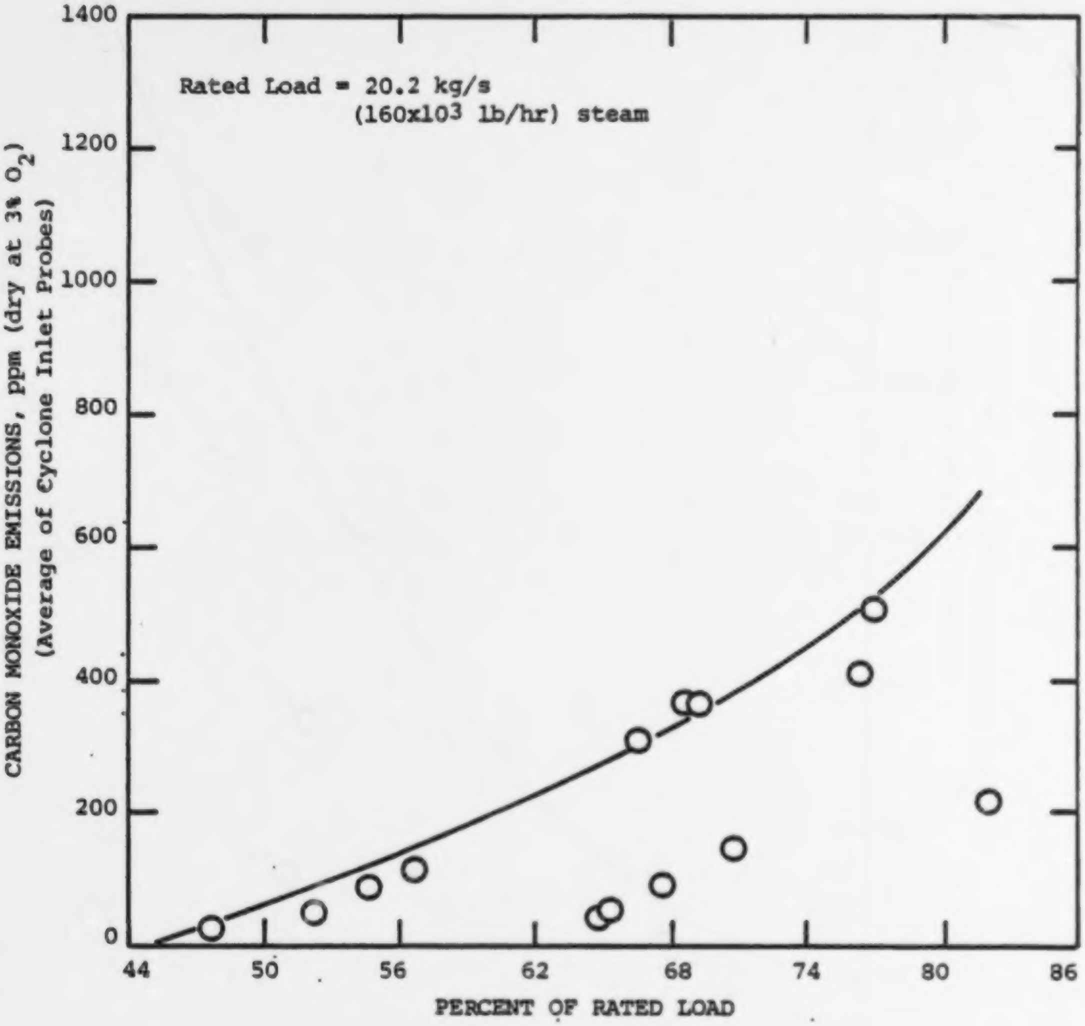


Figure 5.6-8. Carbon monoxide vs. load, Willmar Unit 3, eastern coal.

Figures 5.6-9 and 5.6-10 contain the carbon carryover data as a function of load for western coal and eastern coal respectively. The western coal shows increasing carbon carryover with increasing load while the eastern coal data was a monotonic function of load. The magnitude of the eastern coal carbon carryover was approached only at high loads while firing western coal.

5.6.7 Stoker Operation and Boiler Efficiency

The operational limits of the stoker are presented in Figures 5.6-11 and 5.6-12 for western and eastern coal respectively. The data is plotted as a function of excess O_2 and unit load. The upper dashed line represents the limit of the induced draft fan. The lower dashed line represents the limit defined by fuel bed clinkering, high CO, and/or smoke. The region defined by these two dashed lines is the area of normal operation. The solid line on these figures is drawn through test points within this normal operating range. Comparison of the two solid lines shows that the western coal can be fired at lower excess air than the eastern coal over the entire load range. These plots may also be viewed as defining the limits of staged combsution in this particular unit.

Table 5.6-1 contains a column labeled kg steam/kg coal. On the average the western coal produced 30% less steam per kilogram of coal than the eastern coal. This number gives some indication of how much more coal a plant would have to process to obtain the same steam load. However the actual boiler efficiencies are not so severely impaired as shown in Table 5.6-2 which contains the heat loss boiler efficiency calculation results for eastern coal and western coal respectively. Tests 23-34 are on eastern coal and tests 3-18 are on western coal. On the average the western coal reduced the boiler efficiency by three percent from 80.9% to 78.5%. The largest differences between the two coals occur in the moisture and hydrogen losses. This, of course, is due to the high moisture content of the western coal. There are three factors which would cause loss of steam generation on western

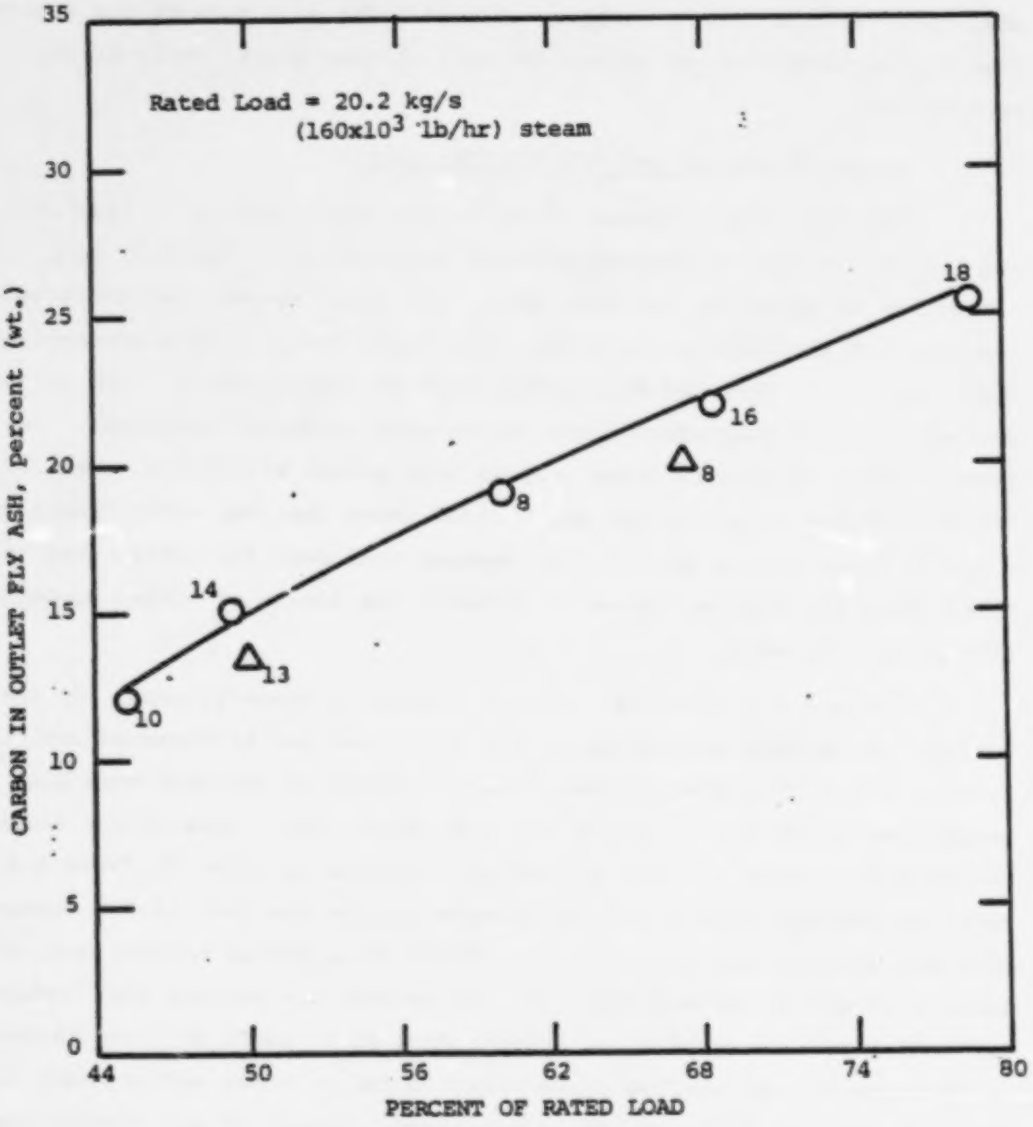


Figure 5.6-9. Carbon vs. load, Willmar Unit 3, western coal.

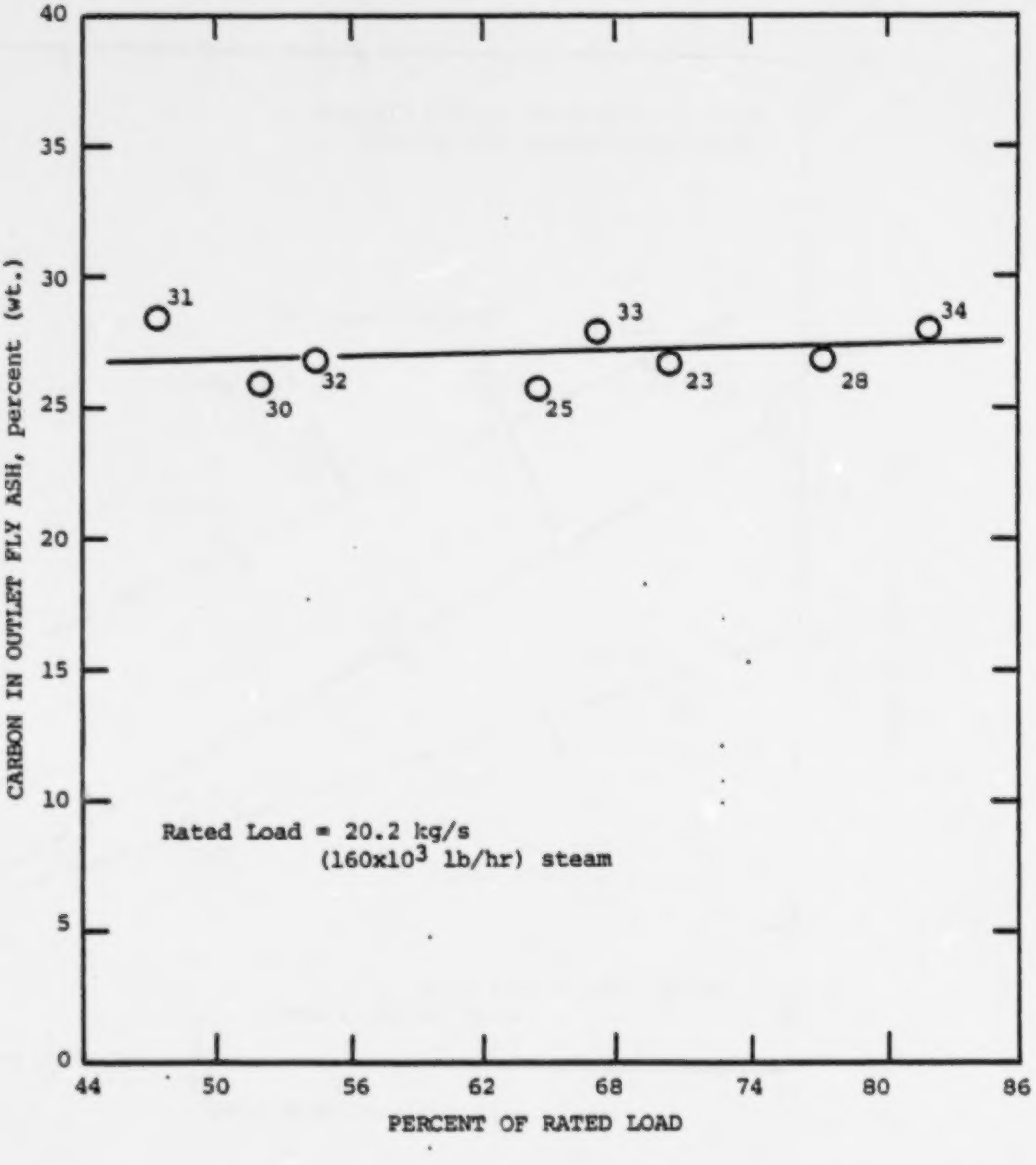


Figure 5.6-10. Carbon vs. load, Willmar Unit 3, eastern coal.

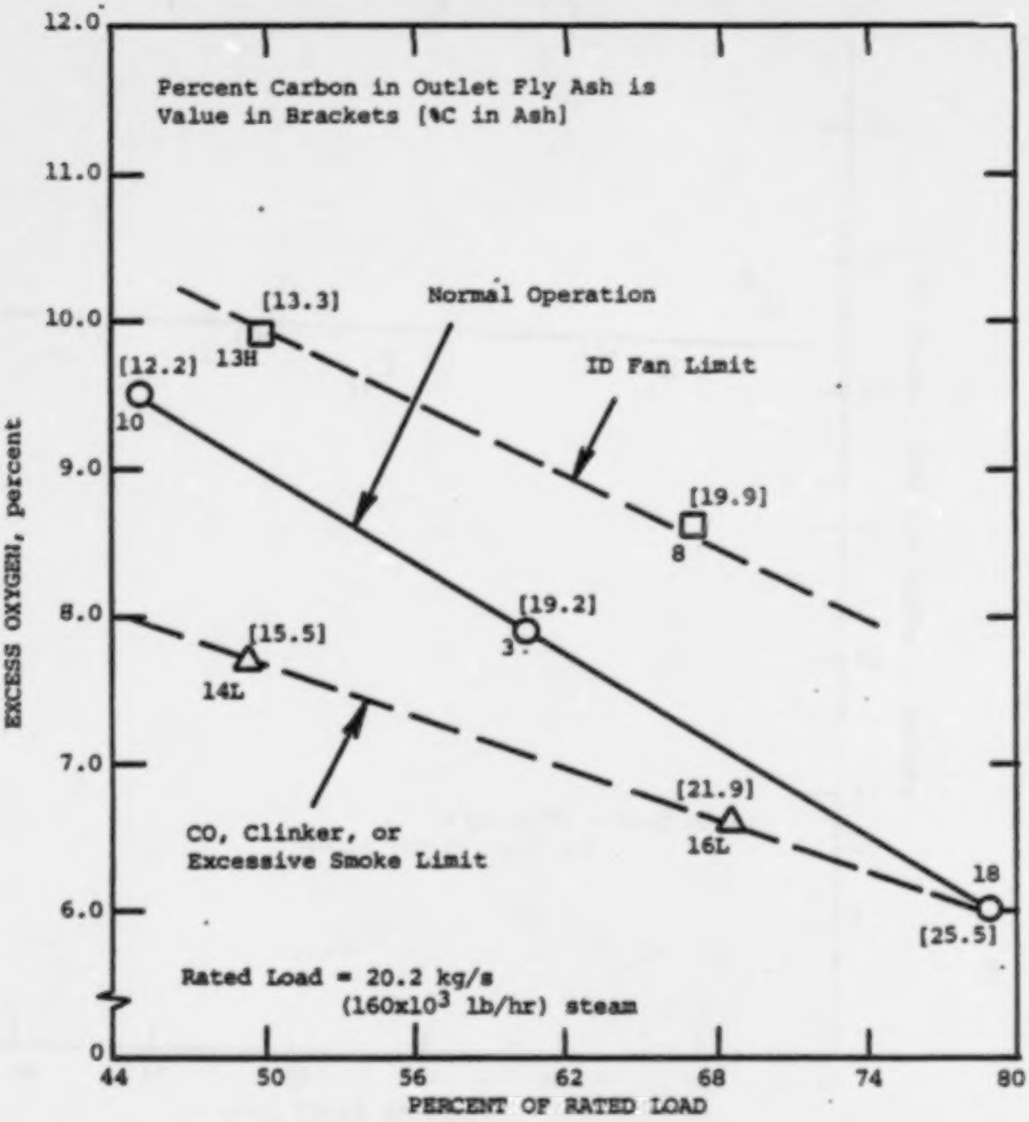


Figure 5.6-11. Excess oxygen vs. load, staging limits, Willmar Unit 3, western coal.

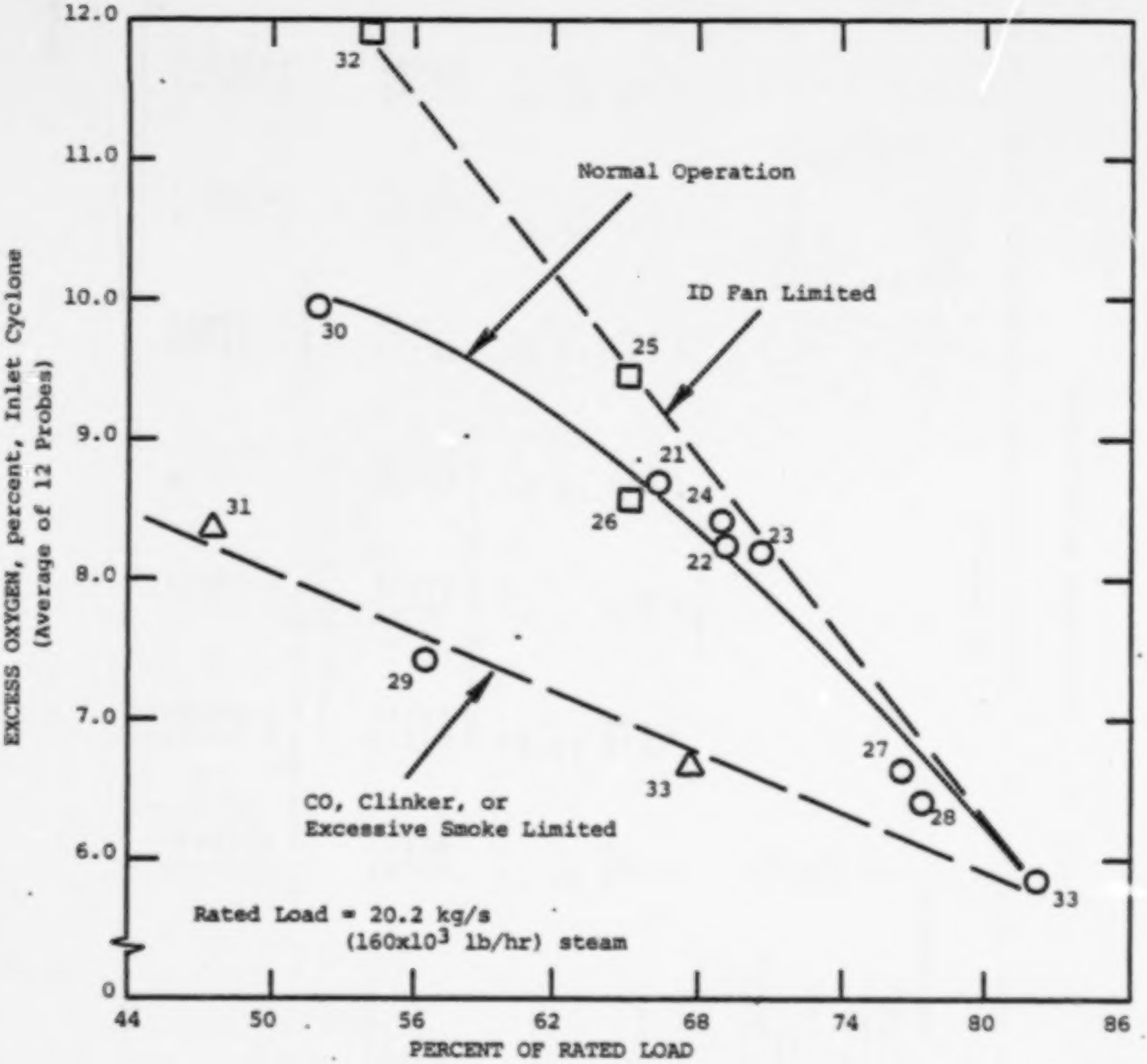


Figure 5.6-12. Excess oxygen vs. load, staging limits, Willmar Unit 3, eastern coal.

TABLE 5.6-2. CALCULATION OF EFFICIENCY

Boiler Category 312

Unit Description

Location No.	4
Boiler No.	3
Furnace Type	WT
Capacity	
kg/s	20.2
10^3 lb/hr	160.0
MBtu/hr	205
Installed	1960
Erection Method	Field
Burner Type	SS

Eastern Coal Fuel Analysis

C	69.26
H	4.73
O	7.47
N	1.37
S	2.28
H_2O	7.11
Ash	7.76
HHV/(Btu/lb)	12440
MJ/kg	28.9

BOILER CONDITIONS								
Test No.	23	25	28	30	31	32	33	34
Test Load, % of Capacity	71.6	65.9	78.4	52.2	47.6	54.6	68.6	83.4
Stack O_2 (% Dry)	8.2	9.4	6.5	10.0	8.4	11.9	6.6	5.9
Stack CO (ppm)	146.0	44.0	509.0	51.0	26.0	84.0	89.0	316.0
Stack Temperature								
°K	484	491	484	473	469	472	500	489
°F	412.5	425.8	411.0	391.5	385.0	390.0	440.0	420.0
Ambient Air Temperature								
°K	302	305	300	303	308	299	301	299
°F	85.0	90.0	81.0	86.5	95.5	78.1	82.5	78.0
Calculated Air Heater Values, percent								
AH Inlet Excess Air	61.86	79.10	43.06	87.40	64.50	127.53	44.82	37.51
AH Exit Excess Air	74.72	106.86	52.86	100.92	75.73	137.34	53.97	50.68
Air Heater Leakage	7.49	14.65	6.51	6.82	6.45	4.14	5.92	8.94
Air Heater Efficiency	36.88	29.47	37.89	38.51	38.93	40.66	29.83	34.67
PCT. Air Through Air Heater	102.15	79.44	110.08	103.29	100.72	115.56	84.92	102.46
BOILER HEAT BALANCE LOSSES, percent								
Heat Balance Losses Corrected to 300 °K (80 °F) Entering Air Temperature								
Dry Gas	10.41	12.74	9.12	11.16	9.42	13.21	10.00	9.28
Moisture + H_2	4.93	4.95	4.93	4.89	4.87	4.89	4.98	4.95
Moisture in Air	0.25	0.31	0.22	0.27	0.23	0.32	0.24	0.22
Unburned CO	0.08	0.03	0.24	0.03	0.01	0.06	0.04	0.10
Combustibles	2.48	2.36	2.49	2.37	2.69	2.48	2.64	2.64
Radiation	0.56	0.61	0.51	0.77	0.84	0.73	0.58	0.48
Boiler Efficiency	81.30	79.01	82.49	80.52	81.94	78.30	81.52	82.34

(continued)

TABLE 5.6-2 (continued).

Boiler Category 312

Unit Description	
Location No.	4
Boiler	3
Furnace Type	WT
Capacity	
kg/s	20.2
10^3 lb/hr	160.0
MBtu/hr	176.0
Installed	1960
Erection Method	Field
Burner Type	SS

Western Coal Fuel Analysis	
C	49.32
H	3.31
O	10.05
N	0.68
S	1.15
H_2O	25.56
Ash	9.12
HHV/(Btu/lb)	8400
MJ/kg	19.5

			BOILER CONDITIONS				
Test No.	3	8	10	13	14	16	18
Test Load, % of Capacity	60.9	67.8	45.0	50.0	49.4	69.4	80.0
Stack O_2 (% Dry)	7.9	8.6	9.5	9.9	7.7	6.6	6.0
Stack CO (ppm)	527.0	332.0	262.0	198.0	179.0	1182.0	2200.0
Stack Temperature							
°K	479	484	462	475	465	450	450
°F	402.0	412.0	373.0	395.0	378.0	351.0	351.0
Ambient Air Temperature							
°K	305	298	304	305	306	301	300
°F	90.0	77.0	88.0	90.0	91.0	82.0	80.0
			Calculated Air Heater Values, percent				
AH Inlet Excess Air	59.0	67.05	80.04	87.28	56.65	44.83	39.12
AH Exit Excess Air	70.57	74.81	97.86	105.61	67.07	54.34	48.90
Air Heater Leakage	6.68	3.82	8.73	9.10	6.57	5.98	6.37
Air Heater Efficiency	38.18	38.38	39.10	36.87	40.29	47.80	49.19
PCT. Air Through Air Heater	100.23	113.73	105.20	99.17	107.30	134.98	143.06
			BOILER HEAT BALANCE LOSSES, percent				
			Heat Balance Losses Corrected to 300 °K (80 °F) Entering Air Temperature				
Dry Gas	9.88	10.61	10.52	11.73	9.04	7.54	7.22
Moisture + H_2	8.11	8.15	8.02	8.09	8.03	7.96	7.97
Moisture in Air	0.24	0.25	0.25	0.28	0.22	0.18	0.17
Unburned CO	0.28	0.18	0.16	0.13	0.09	0.56	0.99
Combustibles	2.80	2.93	1.64	1.81	2.08	3.31	4.04
Radiation	0.66	0.59	0.89	0.80	0.81	0.58	0.50
Boiler Efficiency	78.04	77.28	78.51	77.17	79.72	79.88	79.11

coal, they are: (1) limitation of maximum steam generation due to high superheat temperature, (in this case this limit resulted in a four percent reduction in maximum load); (2) limited coal handling and feeder capacity, (this was not a problem at Willmar); and (3) reduction in boiler efficiency due to increased moisture losses, (efficiency reductions of some three percent were measured when comparing western to eastern coal at comparable load and excess O_2's).

5.6.8 Eastern Coal Burning on Spreader Stoker

Willmar Unit 3 was designed to burn a high heat content eastern type coal. However, the Southern Illinois coal did not perform as well on the Montana coal. There were two reasons for the poor performance of the eastern coal. First, the test batch of eastern coal contained a large percentage of fines. Second, the overfire air fan was not functioning properly. The stoker developed a smoking problem and a Detroit Stoker factory representative was sent out to retune the stoker. The results of that effort are summarized below.

The boiler had a smoking problem when firing the Southern Illinois coal. The field representative from the stoker manufacturer noticed several problems with the boiler operation. First, the furnace draft was too low at -0.203 cm (-0.08 inches) of H_2O when it should have been almost twice that at -0.38 cm (-0.15 inches) H_2O. Second, the feeders on the stoker were out of adjustment in two ways. Both the hand wheels were out of adjustment and the spill plates were not set right. Third, the overfire air was not biased properly and not of sufficient pressure. After determining these three items, correction of the problem proceeded as follows.

First, all spill plates were reset to the factory recommended setting of approximately 1.27 cm (1/2 inch). This adjustment is made by turning the spill plate adjusting screw clockwise all the way in until the center rib of the spill plate bears against the inner end of the screw. The adjusting screw was then backed off counter-clockwise until the 1.27 cm (1/2 inch) setting existed between the rib and inner end of the screw. This was done for all six feeders. Once the spill plates were set the hand wheels were readjusted.

To readjust the hand wheels, which control the feed rate, all the hand wheels were turned clockwise until they could not be tightened anymore. From this position, they were backed off from 1-1/2 to 2-1/2 turns counter-clockwise until a satisfactory fuel bed was formed, up and down the firing lane. From the 1-1/2 to 2-1/2 turn position the adjustment was made in 1/4 turn intervals. This concluded the fuel supply controls adjustment.

The overfire air was then reset. The first problem with this system was that the outlet of the blower was producing only 25.4 cm (10.0 inches) of H_2O pressure and it should have been about 68.6 cm (27 inches) of H_2O. A search for leaks in the overfire air system turned up none. Subsequent discussions with plant personnel revealed that the overfire air blower had been overhauled recently and closer inspection of the blower showed that the impeller had not been reinstalled properly. This reinstallation error resulted in insufficient "bite" by the impeller in the shroud to the fan and a resultant loss in air pressure. To compensate for the low fan capacity a blower from the adjacent unit #4 which was connected via a crossover duct was put in service. This additional fan raised the overfire air supply pressure to the required 68.6 cm (27 inches) of water pressure.

With sufficient air pressure restored to the overfire air system, the overfire air pressures were reset to factory specifications.

An overview of the overfire air settings were such that the back wall was at a higher pressure than the front wall. The back wall upper and lower rows were almost equal at about 43.2 cm (17 inches) H_2O pressure on the upper row and 41.4 cm (16.3 inches) H_2O pressure on the lower rear wall. On the front wall (feeder wall) the overall pressure was lower than the back wall. The upper and lower rows on the front wall were similarly biased. The lower row had about 38.1 cm (15 inches) of H_2O pressure, and only three to four inches on the top row on the front wall. This low pressure was just sufficient to keep the nozzles from heating up and did little to aid combustion. With most of the air through the lower jets the turbulence mixing immediately above the bed was increased. This resulted in increased residence time and improved carbon burnout.

This improved firing mode of the unit allowed the combustion air to be reduced which allowed the furnace draft to be increased. The final boiler configuration was a definite improvement over the initial condition of the stoker but still was not a complete solution to the smoking problem. Some smoking still existed and flue gas analyses of the excess O_2 distribution at the boiler outlet in a test (#34) immediately preceding the boiler tune-up revealed a high degree of stratification in the exhaust duct. This *is shown in Table 5.6-3 which presents the inlet cyclone flue gas distributions.* The cyclone inlet is essentially the same as the boiler outlet. Also, shown in Table 5.6-3 is a flue gas distribution from before the stoker tune up, this was test #23. The important thing to notice is the maldistribution of excess O_2 across the duct from east side to west side. For test 34 the average of east side probes (#1 through #6) is 4.98% excess O_2 and the west side probes (#7 through #12) average 6.79% O_2. A difference of 1.81% excess O_2 from east to west. Test 23's corresponding excess O_2 distribution is 6.69% for the east side and 9.58% for the west side. A change in excess O_2 of 2.89% from east to west. For test 34 the percentage variation of excess O_2 across the duct is 31% and for test 23 the percentage is 35%. The ultimate cause of the maldistribution of fuel and air was not discovered, even though a change in the smoking problem resulted.

Western coal burned better on the stoker. The eastern fuel had a tendency to form clinkers more readily than the western coal. This was probably due to the uneven fuel/air distribution which resulted in local cooling of the ash below its fusion temperature. The poor air/fuel distribution also caused the eastern fires to impinge on the back wall of the boiler. The western coal fires did not do this. Flame impingement and flame carryover into the superheat pendant section which caused slagging was more evident with the eastern than with the western coal. However, high superheat steam temperatures were a problem with western coal and some attemperation was required. Smoking was a continuous problem with the eastern coal firing. Interestingly enough, CO emissions tended to be higher for the western coal firing, yet smoke formation was not a problem as it was with eastern firing. The volatile matter to fixed carbon ration (vm/FC) is higher for eastern coal than for western coal resulting in a burnout problem on eastern coal.

TABLE 5.6-3. FLUE GAS DISTRIBUTION BEFORE AND AFTER STOKER READJUSTMENT

TEST 34 - INLET CYCLONE - 83% load

	1	3	5	7	9	11	
O_2	4.8%	4.6%	4.7%	5.4%	6.55%	7.7%	
CO	278 ppm	258	364	213	69	54	
NO	333 ppm	316	309	312	354	337	
(East) Inlet Averages:	2	4	6	8	10	12	(West)
O_2 - 5.85%	4.85%	5.7%	5.2%	6.3%	7.3%	7.5%	
CO - 216	312	353	399	196	53	53	
NO - 336	331	308	321	331	374	333	

Outlet averages 7.2% O_2, 267 ppm CO, 326 ppm NO

Test 23 - Inlet Cyclone - 72% load

	1	3	5	7	9	11
O_2	6.0%	6.3%	7.45%	8.2%	9.48%	10.95%
CO	360	343	66	91	39	36
NO	444	453	494	534	539	546
Inlet Averages:	2	4	6	8	10	12
O_2 - 8.17%	5.87%	6.9%	7.6%	8.8%	9.3%	10.75%
CO - 145	357	243	87	59	38	35
NO - 491	438	466	500	528	548	558

Outlet averages 9.13% O_2, 177 ppm CO, 439 ppm NO

5.7 FAIRMONT PUBLIC UTILITIES COMMISSION, UNIT #3, FAIRMONT, MINNESOTA

A blend of 1/3 Colstrip, "low sulfur" subbituminous coal and 2/3 Southern Illinois bituminous coal was fired in Fairmont (MN) Public Utilities Commission Boiler #3. The results are compared with the results of firing the Illinois coal alone in the boiler. The blend fired with some difficulty until a number of operational changes were made. Although the blend contained 14% less sulfur in terms of mass per heating value, the sulfur oxide emissions were reduced by only 5%. Other emissions were not substantionally changed.

5.7.1 Introduction

The seventh test site was Boiler 3 of the Fairmont Public Utilities Commission in Fairmont, Minnesota. This site was of particular interest since the unit fired a blend of western and eastern coal in its boiler. The user had attempted firing 100% western coal on the stoker but ran into problems of boiler slagging and high superheat temperatures. The boiler was not equipped with any superheat temperature controlling device such as an attemperator or desuperheater. A maximum blend of western with eastern was determined to be in the ratio of 1/3 western coal with 2/3 eastern coal. This blend was prepared at the site by plant personnel. As will be seen, blending in situ is not an easy task and many problems are encountered.

The data presented will compare the results of tests performed on Unit 3 while firing 100% eastern coal from Southern Illinois and the results of the test series performed on Unit 3 when the eastern coal was blended with the western fuel from Colstrip, Montana. In all, twenty tests were run. Test numbers 1 to 10 were performed on the eastern fuel. Tests 11 to 20 were on the blend. Testing commenced on February 20, 1976, and was completed on April 1, 1976.

A. Boiler Description--

Boiler 3 of the Public Utilities Commission at Fairmont, Minnesota, has a nameplate rating of 10.1 kg/s (80,000 lb/hr) steam flow. The boiler was manufactured by the Erie City Boiler Company. The unit is fired by a spreader stoker also furnished by the Erie City Boiler Company. The stoker has four feeders supplied by a single conical coal distributor.

The boiler supplies superheated steam to a steam turbine which generates power for the rural community of Fairmont. The final steam pressure is 2.9 MPa (400 psig). The steam is superheated to 522 °K (660 °F). The furnace is balanced draft and is kept at about -0.1 cm (-0.15 inches) of H_2O. Forced draft is supplied by a Buffalo Forge F.D. fan. Induced draft is supplied by a single Buffalo Forge I.D. fan. Additionally, a Buffalo fan supplies the forced air for the overfire air blower and ash reinjection system on the back wall of the furnace.

The feedwater is heated by an economizer located in the back pass of the boiler. Hot flue gases from the furnace pass through the superheat section and then through the economizer. The unit has no air preheater, combustion air is supplied at ambient conditions; however, the inlet to the FD fan is inside the building and ambient conditions generally are at least 294 °K (70 °F) or higher. After the economizer, the flue gases pass through a long section of exhaust duct into which three sample ports were installed for the test program. The hot gases then flow through a retrofitted cyclone-type dust collector supplied by Western Precipitator Company. The multiclone dust collector mechanically removes much of the particulates from the exhaust gas before it travels through the ID fan then up the tall smokestack and exits to atmosphere.

B. Stoker Operation--

The spreader stoker is made up of four individually controlled feeders and a singly-driven traveling grate. The grate moves in a continuous motion towards the front end of the stoker. The motion is supplied by a hydraulically operated drive that can be adjusted to vary the speed of the grate depending on the load being carried. Ash is discharged from the grate at the front end of the stoker. The ash falls into an ash hopper below the stoker and is pneumatically removed periodically during the day.

Each feeder can be individually adjusted to vary the quantity and distribution of fuel. Each feeder is supplied with an electric motor with an adjustable pulley arrangement to vary the feeder's rotor speed. By altering the rotor speed and the position of the adjustable split plate, the trajectory of the fuel can be changed. The fuel feed rate is determined by the stroke of the rams located above the spill plate in each feeder. Every feeder is equipped with three separately adjustable rams. The stroke of each ram can be individually adjusted to tailor the fuel bed contour. Correct stoker operation requires the proper setting of ram speed, spill plate position and rotor speed. A final feature of this type of feeder is a natural draft air sweep chamber. This chamber, located just behind and beneath the rotor housing, draws room air through side vents and directs it through a channel in the rotor housing into the feeder throat. Air also enters through holes in the back plate into the feeder throats from the air sweep chamber. This chamber often becomes filled with small pieces of coal and then becomes inoperative. This can result in slight overheating of the feeder plus a loss in the "sweeping" action of the air through the feeder throat.

C. Sample Site Description--

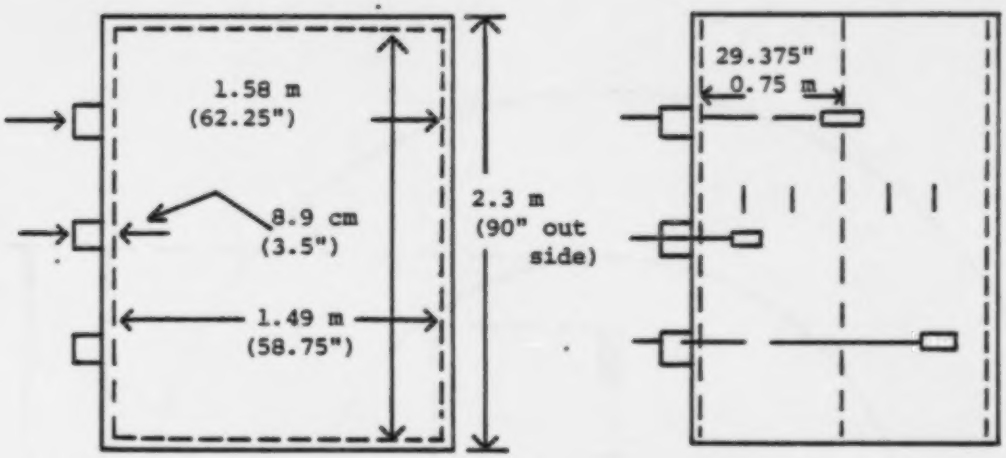
Flue gas was sampled at two locations at Fairmont Unit 3. One was located upstream of the mechanical dust collector in a straight section of exhaust duct. The second was downstream of the cyclone in the stack.

The cyclone inlet location had three sampling ports arranged vertically along the duct. Figure 5.7-1 presents the schematic of the inlet sampling duct configuration. Twelve gaseous sampling probes were used, four each at each port located at the centroids of equal areas. Particulates and SO_x emissions were also measured at this location. A special platform was constructed to permit personnel to test at the site.

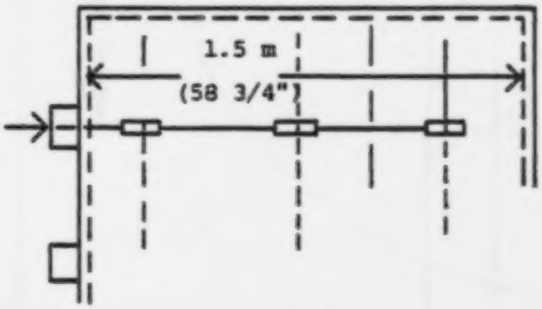
Outlet data for the cyclone was obtained from two ports located on the smokestack. The two ports were located 90 deg apart from one another about 12.2 m (40 ft) up the stack. A catwalk provided access to the ports.

A sampling probe bundle consisting of three stainless steel probes was installed in one port at a time. The orientation of the three stainless steel probes is shown in Figure 5.7-2. When sampling outlet gaseous data, the probes were first sampled in one duct and then the bundle was removed and reinstalled in the other port. Since much of the sampling took place during the winter, the outlet sampling tube bundle had to be heated and insulated to prevent freezing of the sample line.

Inlet - Fairmont


1.58 m
(62.25")
8.9 cm
(3.5")
1.49 m
(58.75")
2.3 m
(90" out
side)
29.375"
0.75 m

End of Port to mid filter - 0.84 m (32.875") + 0.076 m (3") = 0.91 m (35 7/8")
0.34 m (13.3") + 0.076 m (3") = 0.41 (16.3")
1.33 m (52.5") + 0.076 m (3") = 1.4 m (55.5")



1.1 m (42") + 0.66 m (26")
+ 0.076 m (3") = 1.8 m (71")
1.1 m (43")
2.5 m (99")

Figure 5.7-1. Inlet sampling duct configuration, Fairmont Unit 3.

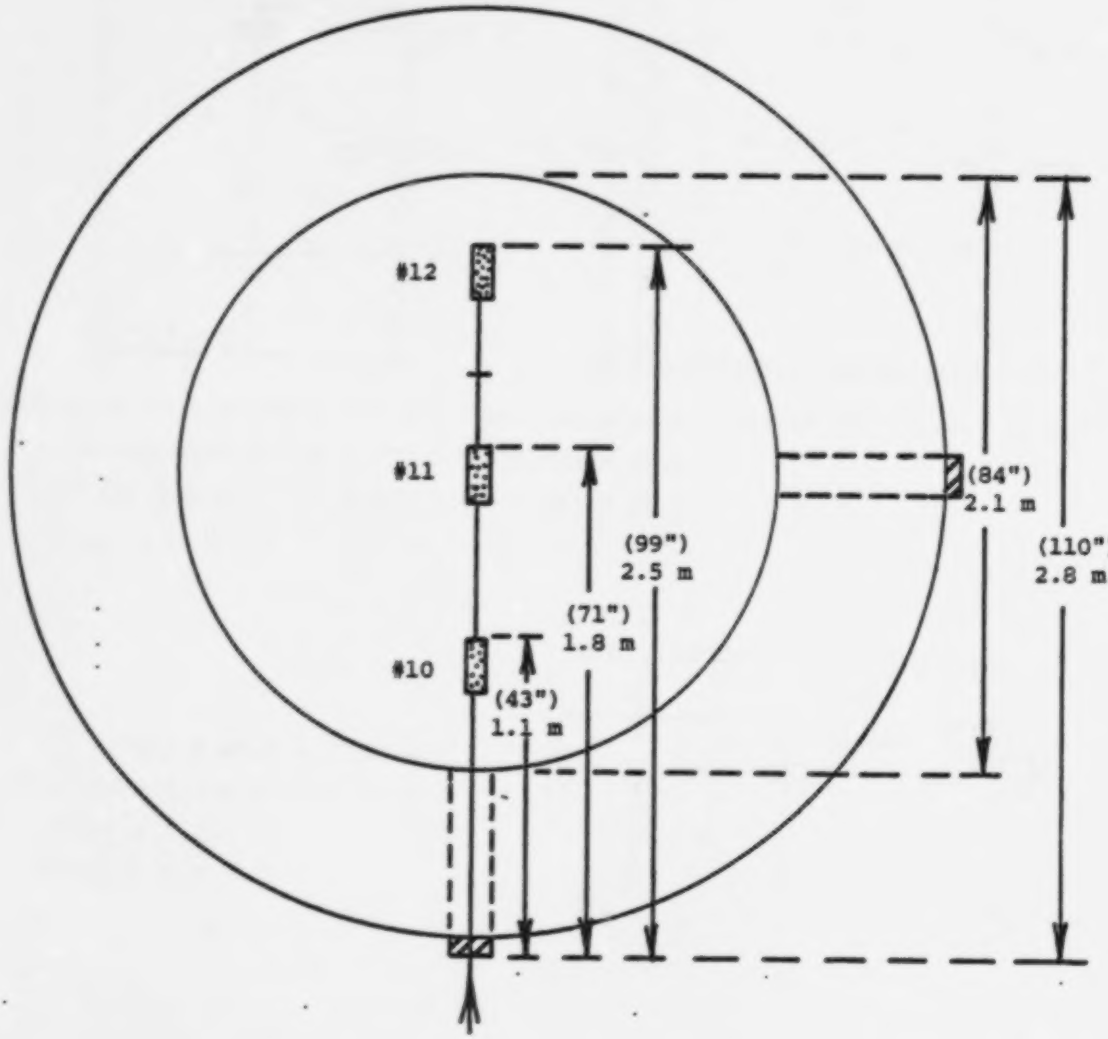

#12
#11
#10
(43")
1.1 m
(71")
1.8 m
(99")
2.5 m
(84")
2.1 m
(110")
2.8 m

Figure 5.7-2. Configuration of outlet sampling probes, Fairmont Unit 3.

D. Comparison of Test Coals--

Two fuels were fired at Fairmont Boiler 3. The first was 100% eastern coal from Southern Illinois. This coal was from the Sahara mine. The second fuel was a blend of 2/3 Sahara coal and 1/3 western coal. The western coal was from the Rosebud and McKay seam of the Big Sky mine in Colstrip, Montana. Table 5.7-1 presents a tabulation of the fuel analysis received on the two coals. Also a composite average column has been made for the 100% eastern coal and the blend. These columns represent an average of the various analyses made for each fuel. If one considers the 100% western fuel analysis, the composite eastern fuel analysis and the composite blend analysis, one can write:

$$X(7949)\text{Btu/lb} + (1-X)(12404)\text{Btu/lb} = 10948\ \text{Btu/lb} \quad (25.5\ \text{MJ/kg})$$

where X = fraction of 100% western in the blend

Solving for X, one finds that the average fraction of western fuel to the total amount of fuel used was 0.327, approximately 1/3. This corresponds well to the intended blending ratio. Also, it is important to note the method employed to collect the fuel samples. During each test a one quart sample of coal was obtained from the coal scale once every hour. Typically, the test would be 5 to 7 hours in duration. These one quart samples would be placed in a large pail and at the end of the test the contents of the pail would be thoroughly mixed. After mixing, the contents would be dumped on a sheet of plastic and the pile arbitrarily halved. One half was returned to the pail for further mixing. The second half was discarded. This process of mixing and halving continued until a suitable pile remained for enclosure in the one quart sample collection can. This final one quart fuel sample was then sent to the laboratory for analysis. Therefore the time-average values for various items in the fuel analysis, i.e. heating value, are representative of the fuel fed over a long period of time but may not be representative of instaneous fuel properties. This may be especially true in the case of the blend. There was some evidence that the coal blend was not as well mixed as the fuel analyses indicate. That is, the indication by fuel analyses that the fuel was well mixed may be due to the fuel sampling technique rather than to the fuel blending procedure.

TABLE 5.7-1. COMPARISON OF TEST COALS AT FAIRMONT UNIT 3

. . .

Test No.	Coal Type	Proximate Analysis, percent					Ultimate Analysis, percent					Ash Fusion Temperatures Reducing/Oxidizing				Higher Heating Value As Received Btu/lb / MJ/kg
		Moisture	Volatiles	Fixed Carbon	Ash	S	H	C	N	O	Cl	Initial Deformation	Softening H=W	H=1/2W	Fluid	
3	Eastern	8.55	--	--	8.35	2.56	4.55	67.96	1.35	6.67	0.01	1430/1603°K 2115/2425°F	1481/1644°K 2205/2500°F	1533/1683°K 2300/2570°F	1578/1706°K 2380/2610°F	12,293/28.6
5	Eastern	6.85	35.03	49.88	8.24	2.53	--	--	--	--	--	--	--	--	--	12,441/28.8
7	Eastern	7.12	33.44	51.37	8.07	1.89	4.57	68.73	0.77	8.76	0.09	1389/1589°K 2040/2400°F	1533/1661°K 2300/2530°F	1561/1683°K 2350/2570°F	1633/1744°K 2480/2680°F	12,318/28.6
9	Eastern	7.79	34.42	50.31	7.48	2.06	--	--	--	--	--	--	--	--	--	12,413/28.9
10	Eastern	6.27	35.53	50.33	7.88	2.01	--	--	--	--	--	--	--	--	--	12,554/29.2
Avg.	Eastern	7.32	34.60	50.47	8.00	2.21	4.56	68.35	1.06	7.72	0.05	--	--	--	--	12,404/28.9
From Coal Pile	100% Western	22.50	31.11	34.36	11.95	0.80	3.10	48.38	0.63	12.54	0.02	1567/1633°K 2360/2480°F	1653/1667°K 2480/2540°F	1656/1689°K 2520/2580°F	1711/1750°K 2620/2700°F	7,949/18.5
12	1 part Western 2 parts Eastern	14.19	31.73	46.39	7.69	1.49	4.21	62.28	0.48	9.62	0.04	1394/1517°K 2050/2270°F	1472/1589°K 2190/2400°F	1489/1617°K 2220/2450°F	1644/1650°K 2320/2510°F	10,922/25.4
15	"	13.83	32.24	46.20	7.73	1.49	--	--	--	--	--	--	--	--	--	10,969/25.5
17	"	12.57	31.64	47.32	8.47	1.70	--	--	--	--	--	--	--	--	--	11,140/25.9
18	"	13.89	31.78	46.65	7.68	1.69	--	--	--	--	--	--	--	--	--	10,761/25.0
Avg.	"	13.62	31.85	46.64	7.89	1.60	--	--	--	--	--	--	--	--	--	10,948/25.5

(continued)

TABLE 5.7-1 (continued).

Test No.	Coal Type	Mineral Analysis of Ash											Sulfur Forms			
		P_2O_5	SiO_2	Fe_2O_3	Al_2O_3	TiO_2	CaO	MgO	SO_3	K_2O	MnO_2	Undetermined	percent Pyrite	percent Sulfate	percent Organic	% Total Sulfur
3	Eastern	0.21	46.54	24.26	21.30	1.05	1.50	0.75	0.86	2.30	0.48	0.67	1.33	0.09	1.14	2.56
5	Eastern	--	--	--	--	--	--	--	--	--	--	--	--	--	--	2.51
7	Eastern	0.20	52.33	14.19	22.50	1.20	2.80	1.13	2.81	2.37	0.32	0.15	0.76	0.11	1.02	1.89
9	Eastern	--	--	--	--	--	--	--	--	--	--	--	--	--	--	2.06
10	Eastern	--	--	--	--	--	--	--	--	--	--	--	--	--	--	2.01
Average	Eastern	0.20	49.43	19.12	21.94	1.13	2.15	0.94	1.84	2.33	0.40	0.41	1.05	0.10	1.08	2.21
From Coal Pile	100% Western	0.20	24.87	4.39	12.15	0.48	44.00	3.12	9.12	0.53	0.22	0.92	0.41	0.07	0.32	0.80
12	1 part Western 2 parts Eastern	0.30	45.42	12.30	22.35	1.00	5.80	2.20	8.75	1.48	0.32	0.02	0.51	0.12	0.86	1.49
15	"	--	--	--	--	--	--	--	--	--	--	--	--	--	--	1.49
17	"	--	--	--	--	--	--	--	--	--	--	--	--	--	--	1.70
18	"	--	--	--	--	--	--	--	--	--	--	--	--	--	--	1.69
Average	"	--	--	--	--	--	--	--	--	--	--	--	--	--	--	1.60

5.7.2 Eastern Coal Blended with Western Coal Burning on Spreader Stoker at Fairmont Unit #3

Testing on the one part western coal to two parts eastern coal began with Test #11 on March 9, 1976. It became readily apparent during Test #11 that a severe operating problem existed on the unit when it fired the blend. The problem was that clinkers would form on the grate directly under certain feeders. Raw coal would pile up on these clinkers and slowly ignite or smolder forming a larger clinker. The problem, as found, is described in this section along with the test program developed to try to solve the problem. Also included in this section is an outline of the eventual solution to the clinkering problem and an evaluation of the successfulness of that solution. Finally, this section will conclude with a discussion of the blending process used at the site.

Test #11 started the test series on the blend at Fairmont Unit #3. The blend was to be one part Montana coal and two parts Southern Illinois coal. From Section 5.7.1.D it is seen that the overall blend was essentially in that ratio (although there is some doubt as to whether the instantaneous blend was in those proportions). Test #11 was a high load test in the as-found operating mode. The conditions found on the stoker for this first run on the blend were as follows. The ash bed thickness across the width of the grate was non-uniform. The ash bed thickness on the #4 feeder side (east side) was 3.8 cm (1-1/2 inches) while the ash bed thickness of the #1 feeder side (west side) was 6.3 cm (2-1/2 inches). Fingers of glowing embers of coal were tending to fall into the ash pit directly below each feeder. Coal was piling up just beneath each feeder on the top of clinkers that had formed directly in front of each feeder. The problem was particularly severe on the second feeder from the west side, feeder #2. On feeder #2, much of it's coal supply dropped directly in front of the feeder, piled up and formed clinkers.

These raw coal pile clinker formations had to be individually broken up by the boiler operator using a hand rake. The job was time consuming and difficult. If the coal pile/clinkers were not raked, the raw coal could (1) continue to pile up until coal began to back up into the throat of the feeder, or (2) coal could begin burning at the top of the clinker and spread fire back into the feeder. Additionally, the raw coal could ride on top of the clinker and would be dumped into the ash hopper. One obvious problem is a loss of efficiency due to dumping raw fuel into the ash pit. A second problem is the possibility of the raw coal igniting in the ash hopper. A third possible problem of the clinker would be inadequate cooling of the grate. The clinker covered area can become overheated and melt or warp the grate plates. This, in turn, can easily cause destruction of the grate and a forced outage.

During test #11 there was no "flash backing" of fires into the feeders as seen on 100% eastern coal burning. It was felt that this may not be particularly due to the blend being burnt, but to the fact that the coal on that day appeared wetter and perhaps the fines (believed to be responsible for the "flashing back" phenomenon) were sticking to the larger pieces of coal.

The following paragraphs outline the procedure followed in defining a modified operating mode to eliminate clinkering.

Why were the clinkers and coal piles forming? The coal piles were caused because the clinker underneath formed an effective shield between undergrate air and the raw fuel. Hence, the fuel would not ignite and would continue to collect in a pile until air circumventing the clinker could reach the edges of the pile and ignite the coal. Another possibility is that the clinker would not entirely block the air flow but impede it sufficiently to locally starve the incoming raw coal of air and form a larger clinker. If the clinkers were eliminated the coal piling phenomenon would also be solved.

Two theories of clinker formation were developed. The first was a chemical theory where the lower ash fusion temperature of the blend caused the clinker. The second theory related the clinker problem to a physical property of the fuel. If the latter was the case, then a change in operating variables might eliminate the problem. Since the ash fusion temperature was fixed for the coal, the physical theory was adopted and changes in the operating parameters on the stoker were employed to solve the clinker problem.

What physical property of the coal could cause the clinkers? Several answers could be posed but a persistent one was "the fines in the coal." The fine particles in the fuel seemed a strong candidate for a cause of the clinkering. Western coal is known for its tendency to shatter and break down into small particles. Since the clinkering was not seen with 100% eastern coal, perhaps the addition of the component of western coal added extra fines into the coal supply thus causing the clinker. If it were the fines, then how did they cause the clinker? Two mechanisms were considered. The first suggested that the fines were too light to remain on the grate and "blow holes" were formed where the particles were blown off the metal. This would cause hot spots that would raise local temperatures high enought to reach fusion temperatures of the ash, causing clinkers to form. A second mechanism suggested a plugging up of grate air holes by the fine material of the fuel and that these "no-flow" grate areas became hot spots and formed clinkers, It was never resolved which mechanism caused the clinker formation but it was established that the fines in the coal were causing the clinker problem.

Rotor speed setting changes were a starting point in the search for a solution to the clinker formation problem. The unit was set at a load of about 7.6 kg/s (60x10^3 lb/hr) steam flow and the rotor speeds were left in the as-found position. The clinker problem was as originally noted; that is, well defined zones of coal piles/clinkers were formed directly in front of the feeders, especially feeders #1 and #2. The rotor speed was then increased as follows. Each feeder has an individually controlled rotor speed motor connected to the rotor by a variable tension pulley belt. Each rotor speed adjusting handle was turned in a counter clockwise direction until the slack was taken up in the drive belt. Then an additional two turns counter clockwise were given to each handle. Indicators on the side of the motor/pulley housing indicated a 0.6 cm (1/4 inch) change in position. By increasing the rotor speed it was hoped that the trajectory of the fuel towards the back of the boiler would increase. This procedure should prevent the coal from falling directly onto the area in front of the feeders. There was no improvement as a result of this move.

The stoker performed well over the weekend in the modified spill plate mode. In order to further verify the validity of the spill plate adjustment, the spill plate position of #2 feeder was returned to its original as-found setting and the grate was observed. Within forty minutes, a clinker began to form just off feeder #2. After 1-1/2 hours had passed, a definite clinker of moderate size was formed.

The situation overnight was one of continued problems with clinker formation. Much hand raking and attention was required to keep the stoker operating. Feeder #2 spill plate was returned to the successful 6.5 cm (2-1/2 inch) position and the clinker disappeared.

This new operating mode became the established mode for day-to-day firing. The remaining tests on the blend was with the #2 feeder spill plate backed off to the 6.3 cm (2-1/2 inch) mark while the remaining three feeders (#1, #3, and #4) were at the 5 cm (2 inch) mark. This mode proved successful in controlling clinkers. Some additional problems with clinkers did occur from time to time during the remaining test series but they were not as severe or persistent as the original ones. Some minor adjustments were made in the feeder #2 spill plate later in the program but essentially it remained set back farther than its adjacent feeder's spill plates.

A. Blended Eastern and Western Coals as a Boiler Fuel--

Coal blending is not a new concept. Coal producers have for many years blended different seams of coal to produce a specific product. This blending usually takes place at the mine or in some coal preparation facility near the coal mines.

Today there is considerable interest in blending the high sulfur eastern and midwestern coals with the low sulfur western coals to achieve SO_x emission control and to promote the use of the abundant western coal resources. Several problems occur when one contemplates the blending of these coals. Some of these are:

- Long transportation distances to bring the coals together,
- Poor handling characteristics of most western subbituminous coals,
- Fires in storage piles,

- Poor mixing due to size differences of the coals,
- Lack of blending facilities,
- Problems with on-site blending,
- Problems with coal feeders, and
- Combustion-related problems.

With the exception of the first two, the problems listed are open to at least partial solution. It is the intent of this report to identify the specific problems that occur while firing a blend of Montana subbituminous coal and Southern Illinois bituminous coal, and to recommend solutions.

B. Discussion--

Blending coal at a boiler is difficult. Tracing the coal flow through the handling system shown in Figure 5.7-3 shows that the coal can only be mixed in three locations: (1) the coal silo, (2) the conical coal hopper, and (3) in the furnace. The extent of mixing depends on the diameter of the receptacle and the height to which it is filled. If the diameter of the receptacle is small compared to the length of the coal, then the coal will stay stratified. Mixing will occur in the furnace, however, due to combustion. This mixing is limited to the residence time of the coal in the furnace and the size of each parcel of unblended coal that arrives at the furnace feeders.

The mixing problem is compounded by the size variation of the two coals. In any hopper, feeder, or silo there will be some segregation of coal due to the separation of the "fines" from the larger pieces. In the present case, the western coal with its larger percentage of fines will tend to separate from the eastern coal even if it was originally well mixed. This causes severe feeding problems with stoker fired units since the finer coal is not thrown as far into the unit and tends to build up on the chain grate immediately in front of the feeder, causing a clinker to form. Another manifestation of this problem appears in the form of uneven distribution of fines to the feeders, resulting in an uneven fuel bed which can lead to a clinker.

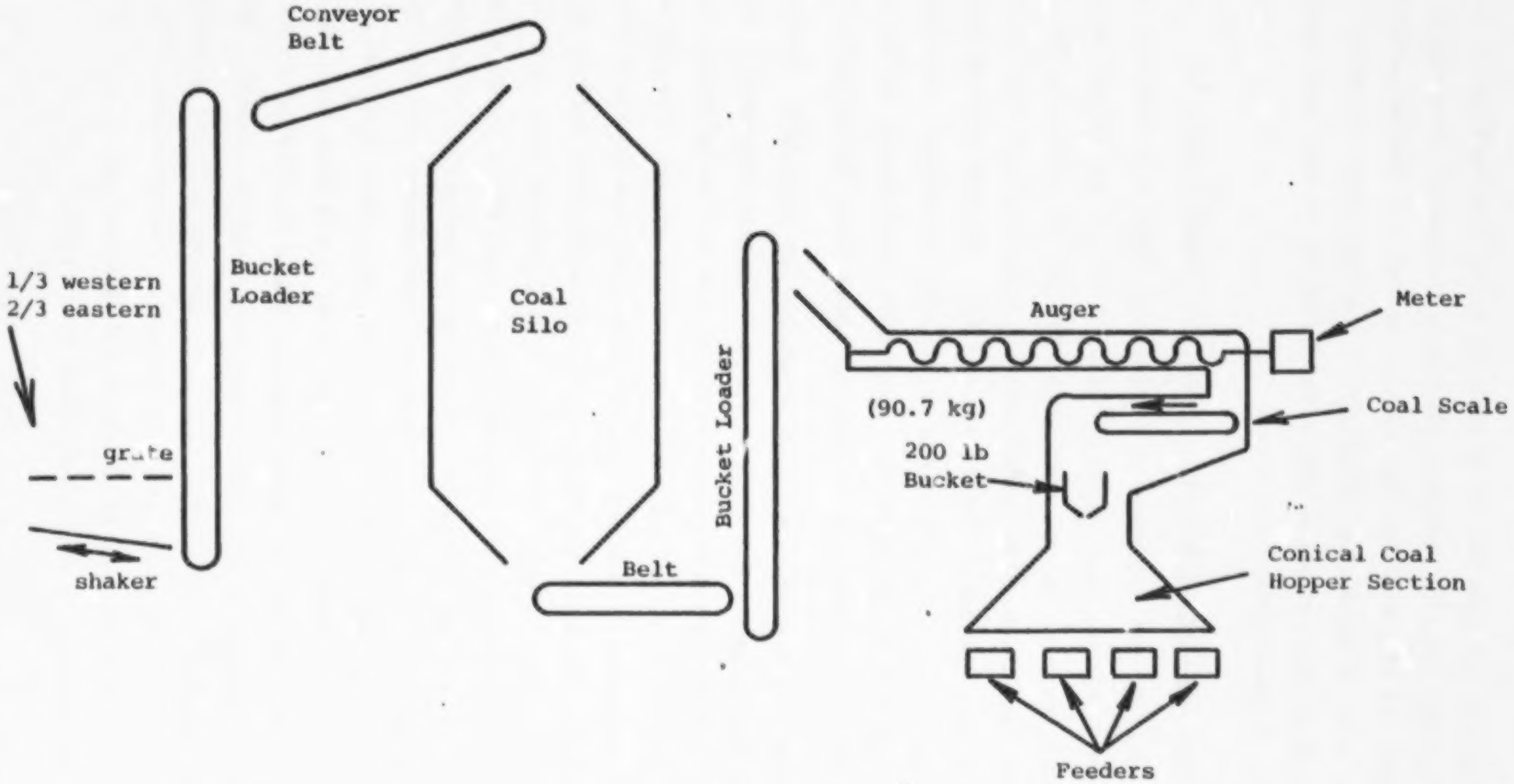

Conveyor Belt
1/3 western
2/3 eastern
Bucket Loader
Coal Silo
grate
shaker
Belt
Bucket Loader
Auger
Meter
(90.7 kg)
Coal Scale
200 lb Bucket
Conical Coal Hopper Section
Feeders

Figure 5.7-3. Schematic of coal handling system, Fairmont, Minnesota Public Utilities Commission.

Adjustments can be made to the stoker to allow the feeding of off-size coal. If the feed coal is uniform, this will result in acceptable operation. However, if the size of the coal is uneven, no feeder setting is adequate. In the case at hand, the blending of the two coals actually aggravated the feeding problem since the added handling of the coal during blending served to further reduce the size.

5.7.3 Eastern Coal Burning on Spreader Stoker at Fairmont Unit #3

Fairmont Unit #3 was designed to burn a high Btu/lb bituminous eastern coal. The Southern Illinois coal fired on Unit #3 stoker performed well. A series of ten tests were run on the unit while firing the Illinois fuel. These tests were at high, medium and low loads ranging from 7.9 kg/s (62.6×10^3 lb/hr) steam flow to 3.6 kg/s (28.6×10^3 lb/hr) steam flow. Various excess air levels were tested at each load. Once each test was set up, the stoker required little or no attention from the boiler operator. The unit held steady state conditions well. There was a minor clinkering problem at times when firing this coal.

When firing the eastern fuel a thin ash bed is required. Generally, a protective ash thickness of 2.5 to 5 cm (1 to 2 inches) was used. This ash bed was of uniform thickness across the width of the traveling grate, indicating a uniformly distributed fuel bed laterally across the grate. The ash was completely burnt out when it reached the ash discharge end of the stoker. No embers were present. Clinkers sometimes were a problem with eastern coal firing. Generally, this was when the flames were flashing back into the rotor housing on #3 feeder. On one test in particular (Test #7), a large clinker formed off the #3 feeder and had to be removed by a hand rake. The same fines that caused the flash back caused the clinker. This occurs when the fine coal drops in front of the feeder and forms a clinker just below the feeder throat on the grate. The fused material forms a patch of grate area that doesn't receive any air flow. Additional fuel material falls on this patch and smolders instead of burning completely and soon a larger clinker is formed. These clinkers must be removed or they will fall into the ash pit and complete combustion there, forming a potential fire hazard. This problem of flame flash-back and clinker formation in front of the feeders was not as severe as it was when the western/eastern coal blend was burned.

The flames on eastern coal firing were a luminescent orange-red in color. There was no flame impingement on the front, back or side walls. One minor problem persisted from time to time, and that was "flame lick" back into the number 3 feeder's rotor housing. This problem is thought to be caused by the fine particles in the feeder not being thrown clear of the rotor and combusting in front of the feeder. If this problem becomes severe, the fires can either coke up the rotors or make their way back up into the fuel distributor and cause damage. The problem was not severe on the eastern coal firing.

Dark gray smoke would rise up from base of the back wall when eastern coal was fired. However, the smoke was directed into the flames and was apparently consumed before exiting through the furnace. Sparklers were slight to moderate in the furnace.

The maximum load tested on Unit #3 was 7.9 kg/s (62,600 lb/hr) steam flow. This was not the maximum continuous load possible on this boiler. The high maximum test load was defined by how much steam the available steam turbines could handle. The plant's main (and largest) steam turbine was down for overhaul during the test program and the turbines remaining in service could not handle all the steam that Unit 3 boiler could potentially generate. Plant personnel estimated a possible maximum continuous load of about 10.1 kg/s (80,000 lb/hr) steam flow on the eastern fuel.

5.7.4 Emissions

Fairmont, Unit #3 emissions were characterized by an eight point test matrix as shown in Figures 5.7-4 and 5.7-5. The numbers on these and all following graphs refer to test numbers and can be used for cross reference. This section is divided into four subsections describing the various emissions. They are particulates, sulfur oxides, nitric oxide, and combustion efficiency related emissions such as carbon monoxide, carbon retention in the ash and thermal efficiency of the unit. A summary of all the gaseous emissions is included in Table 5.7-2.

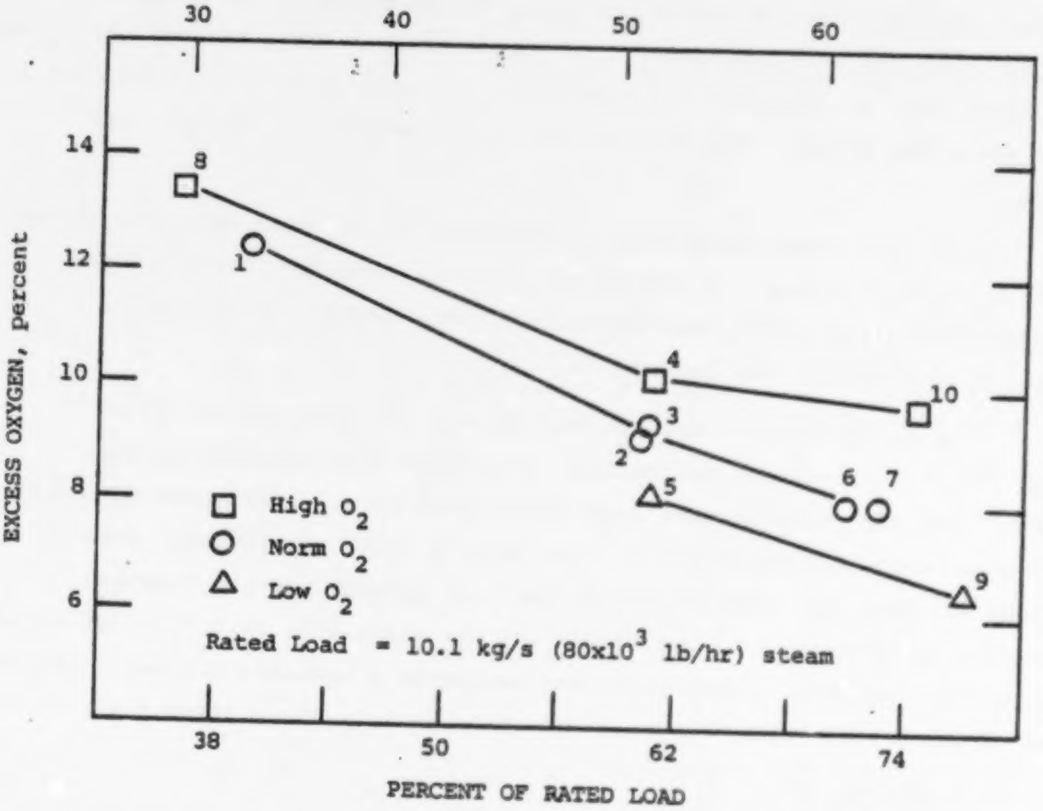


Figure 5.7-4. Conditions under which unit was tested, Fairmont Unit 3, eastern coal.

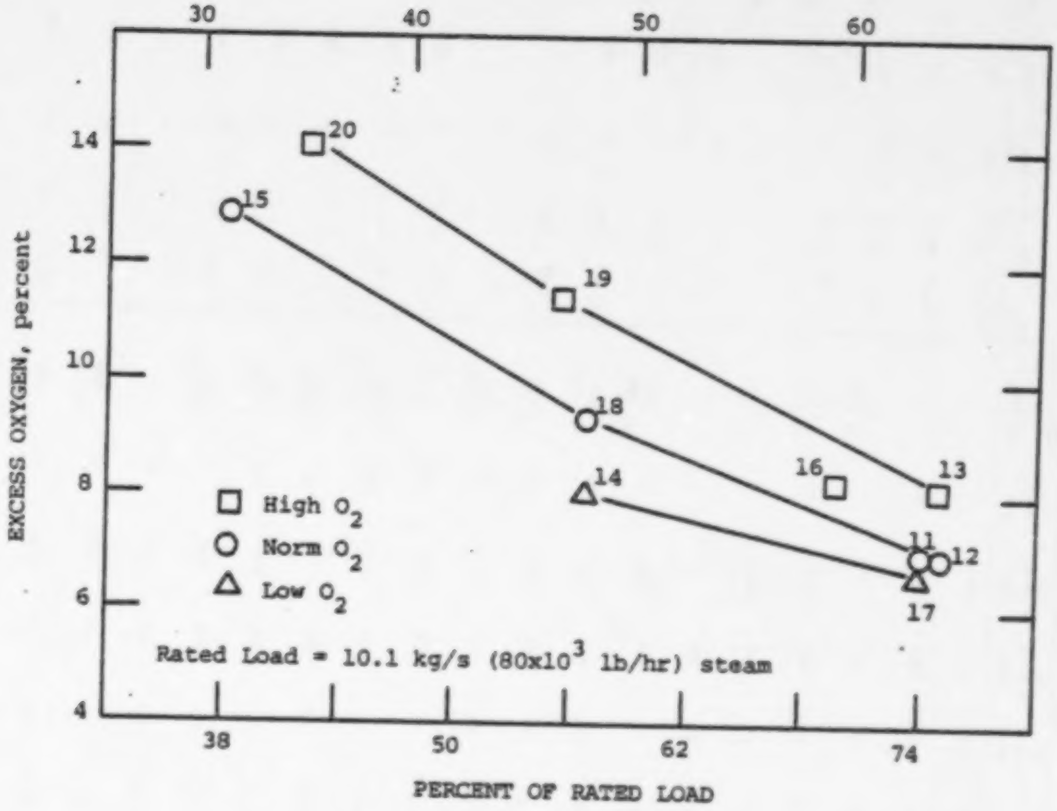


Figure 5.7-5. Conditions under which unit was tested, Fairmont Unit 3, coal blend.

TABLE 5.7-2. GASEOUS EMISSIONS SUMMARY, FAIRMONT PUBLIC UTILITIES COMMISSION, UNIT 3

				Dust Collector Inlet							Stack				
Test No.	Date 1976	Load kg/s (10^3 lb/hr)	Conditions	O_2, %	CO_2, %	CO @ 3% O_2 ppm	NO @ 3% O_2 ppm	SOx @ 3% O_2 ppm	SO_3 @ 3% O_2 ppm	Particulates ng/J (lb/MBtu)	O_2, %	CO_2, %	CO @ 3% O_2 ppm	NO @ 3% O_2 ppm	Particulates ng/J (lb/MBtu)
1	2/20	4.0 (31.5)	Low Load, Norm O_2	12.40	6.49	115	311	1585	77	--	13.06	6.32	160	285	--
2	2/24	6.1 (48.6)	Med Load, Norm O_2	9.09	8.89	51	333	1673	82	--	9.70	8.63	51	227	--
3	2/25	6.2 (48.9)	Med Load, Norm O_2	9.32	8.46	38	320	--	--	618 (1.437)	10.10	8.40	34	280	163 (0.379)
4	2/26	6.2 (49.2)	Med Load, High O_2	10.08	7.82	32	388	1740	31	639 (1.486)	11.41	7.20	41	314	133 (0.309)
5	2/27	6.2 (48.9)	Med Load, Low O_2	8.16	9.44	81	265	1434	12	527 (1.225)	--	--	--	--	125 (0.294)
6	3/1	7.2 (57.4)	High Load, Norm O_2	8.03	9.24	41	391	--	--	--	8.80	9.70	44	317	--
7	3/2	7.2 (58.8)	High Load, Norm O_2	7.99	9.53	52	313	1949	33	757 (1.760)	8.15	10.10	56	312	170 (0.395)
8	3/3	3.6 (28.6)	Low Load, High O_2	13.53	5.63	208	422	1797	23	630 (1.465)	14.00	5.60	219	450	191 (0.444)
9	3/4	7.9 (62.6)	High Load, Low O_2	6.45	11.07	155	282	1682	9	1110 (2.582)	8.78	9.60	127	302	198 (0.414)
10	3/5	7.6 (60.5)	High Load, High O_2	9.76	8.33	81	411	1445	37	1068 (2.484)	--	--	--	--	200 (0.464)
11	3/9	7.6 (60.2)	High Load, Norm O_2	6.95	10.89	77	278	1539	18	--	8.20	10.40	77	260	--
12	3/17	7.6 (61.0)	High Load, Norm O_2	6.95	10.98	72	303	1636	12	1104 (2.567)	7.97	10.37	57	311	222 (0.517)
13	3/18	7.7 (61.1)	High Load, High O_2	8.06	10.80	83	353	--	--	1201 (2.794)	8.70	10.07	76	354	199 (0.463)
14	3/22	5.8 (45.9)	Med Load, Low O_2	8.01	10.20	88	372	1615	54	1209 (2.811)	8.83	9.13	75	360	177 (0.411)
15	3/23	3.8 (30.2)	Low Load, Norm O_2	12.94	6.26	519	413	1248	7	1677 (3.900)	13.00	5.93	375	420	271 (0.630)
16	3/24	7.1 (56.4)	High Load, Norm O_2	8.26	10.68	299	338	1828	50	--	--	--	--	--	--
17	3/25	7.6 (60.0)	High Load, Low O_2	6.62	11.78	349	307	1502	16	909 (2.114)	7.08	10.97	507	296	211 (0.491)
18	3/30	5.8 (45.7)	Med Load, Norm O_2	9.37	9.40	165	323	1672	164	987 (2.295)	10.27	8.50	190	335	208 (0.484)
19	3/31	5.5 (44.0)	Med Load, High O_2	12.40	8.32	189	349	1565	32	935 (2.174)	12.40	--	--	--	233 (0.542)
20	4/1	4.3 (33.8)	Low Load, High O_2	14.13	5.74	805	415	1439	14	1565 (3.639)	13.95	5.60	627	425	248 (0.576)

A. Particulates--

Particulates were measured at both the inlet to the dust collector and in the stack using EPA Method 5. At the inlet, seven point traverses were made at each of the upper two ports. The bottom port was found to be unusable for particulates because its proximity to the platform floor did not allow enough room for the filter box. Inlet particulates were corrected for excess O_2 using the average of a nine-point gaseous traverse made in conjunction with the particulate sampling. Figure 5.7-2 shows the inlet sampling area with gaseous probes installed.

In the stack, two ports at 90 deg to each other allowed for a thirty-two point "equal area" traverse as described in Method 1, the Federal Register. Excess O_2 used for correcting the data was obtained from a three probe bundle installed alternately in the port not being used for particulate sampling.

Figure 5.7-6 illustrates the particulate loading at the dust collector inlet for both fuels. The eastern coal behaved as might be expected. Particulates remained relatively low except at high loads where vertical gas velocities were high enough to "blow" some of the ash off the grate. The critical load above which particulates were observed to rise sharply occurred at about 7.2 kg/s ($57x10^3$ lb/hr), or 71% of design load.

The particulate behavior for the coal blend firing did not resemble that of the eastern coal. On the average, the dust collector loading was 36.2% greater with the blend than with the eastern coal. Also, a sharp rise in particulate loading was observed at low loads. The explanation for this behavior is not readily apparent. Carbon carryover, Figure 5.7-10, was actually lower for the blend and thus cannot explain this difference.

The ash content of both fuels was very similar, averaging 8.64% for the eastern coal (5 samples analyzed) and 9.14% for the blend (4 samples analyzed). Sodium content and ash fusion temperatures were also very similar (see Table 5.7-1). However, the coal blend was observed to have more fines in it, and this combined with the noncoking properties of the western coal probably accounts for the increased particulates of the coal blend.

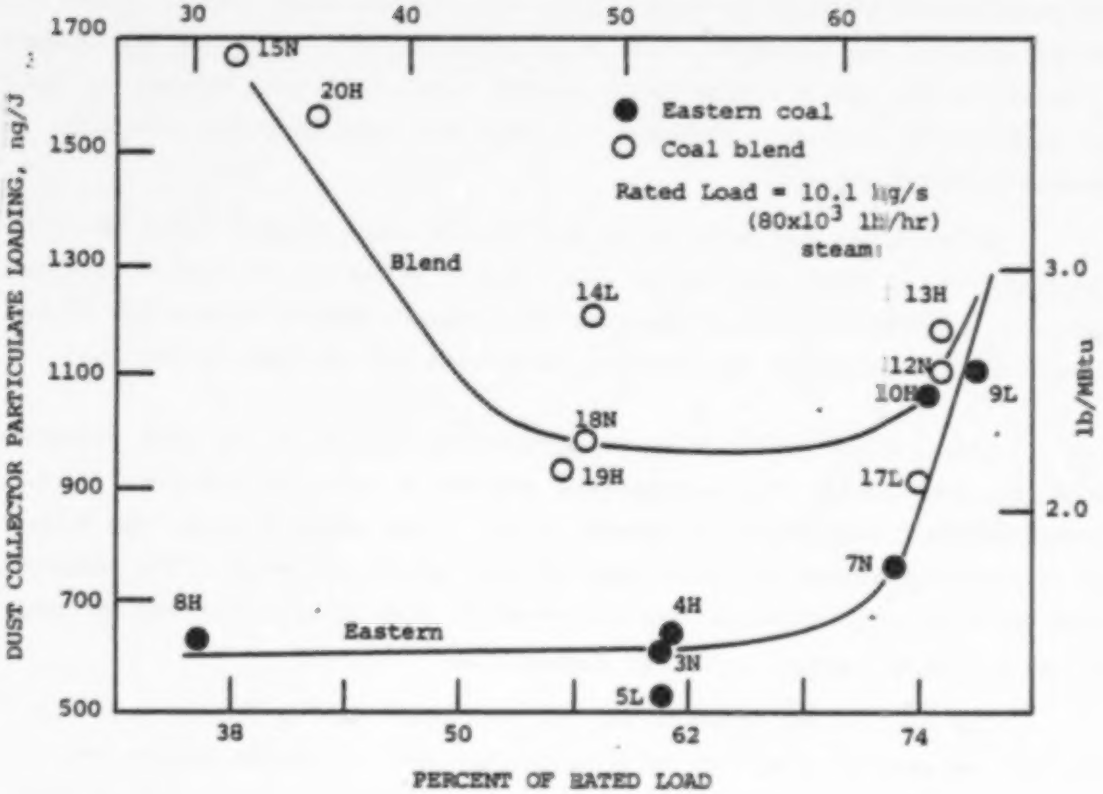


Figure 5.7-6. Inlet particulates vs. load, Fairmont Unit 3.

As for the rise at low loads, it is likely that agglomeration of suspended ash particles does not occur as readily at the lower loads because of the accompanying lower temperatures. Thus, the particles remain smaller and are more easily carried over into the flue duct.

Figure 5.7-7 illustrates the particulate loading in the stack. As was observed at the dust collector inlet, the coal blend firing produced a 33.3% higher particulate loading in the stack than did the eastern coal firing. With the exception of Test #15, however, both fuels met the applicable emissions regulation for this unit of 258 ng/J (0.6 lb/MBtu).

Cyclone efficiency increases not only with increasing particle size and inlet velocity, but also with increasing inlet loading (see Figure 5.7-8). This would certainly explain the shape of the dust collector efficiency curves shown in Figure 5.7-9. Here, the increase in cyclone efficiency at low loads with the coal blend can be accounted for by the sharp rise in inlet loading.

Combustibles in the fly ash were an average 18.1% lower while firing the blend as shown in Figure 5.7-10. And, they are seen to increase at low loads where combustion conditions (primarily temperature profile and fuel air mixing) are inadequate to complete their combustion. Exactly why the blend firing showed lower percent combustibles in its fly ash is unknown. However, it should be noted that the total carbon carryover on a heat input basis would show that both fuels emitted approximately the same amount of combustible material.

B. Sulfur Oxides--

Sulfur oxides were measured at the inlet to the dust collector from a single point. To help determine the validity of this sample location, sulfur oxides were measured at both the inlet to the dust collector and at the stack during test #2. Very good agreement was found with the stack showing 1.26% more SOx than the inlet. This difference is well within experimental error.

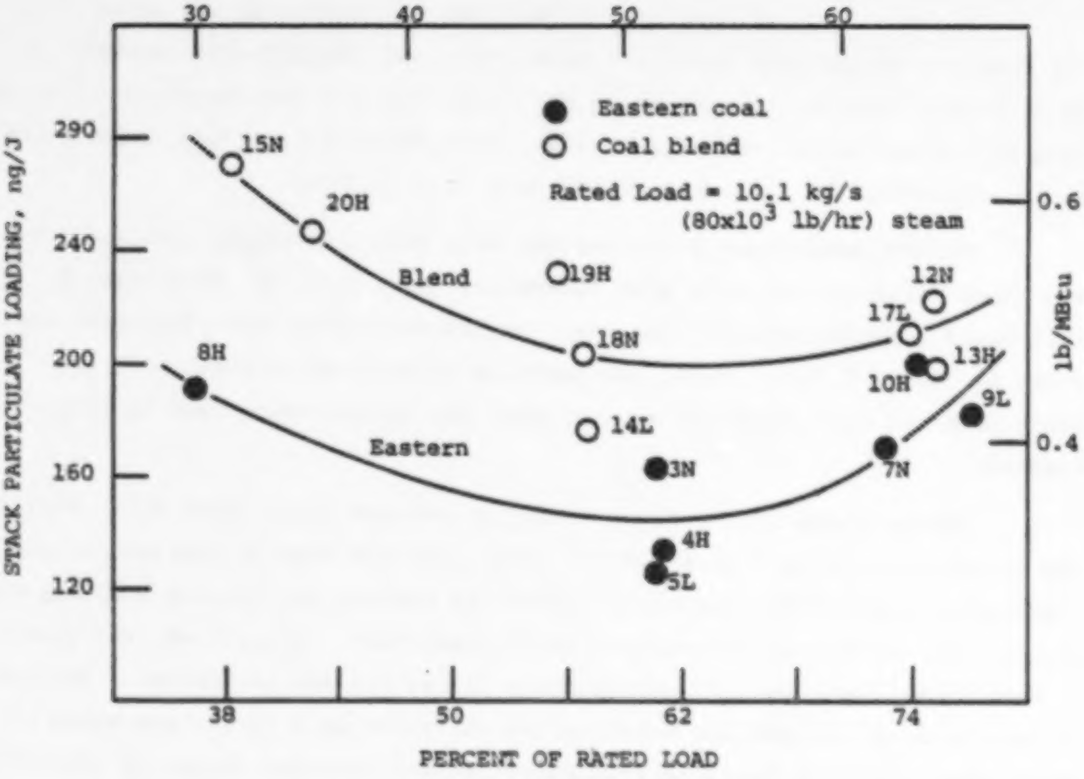


Figure 5.7-7. Outlet particulates vs. load, Fairmont Unit 3.

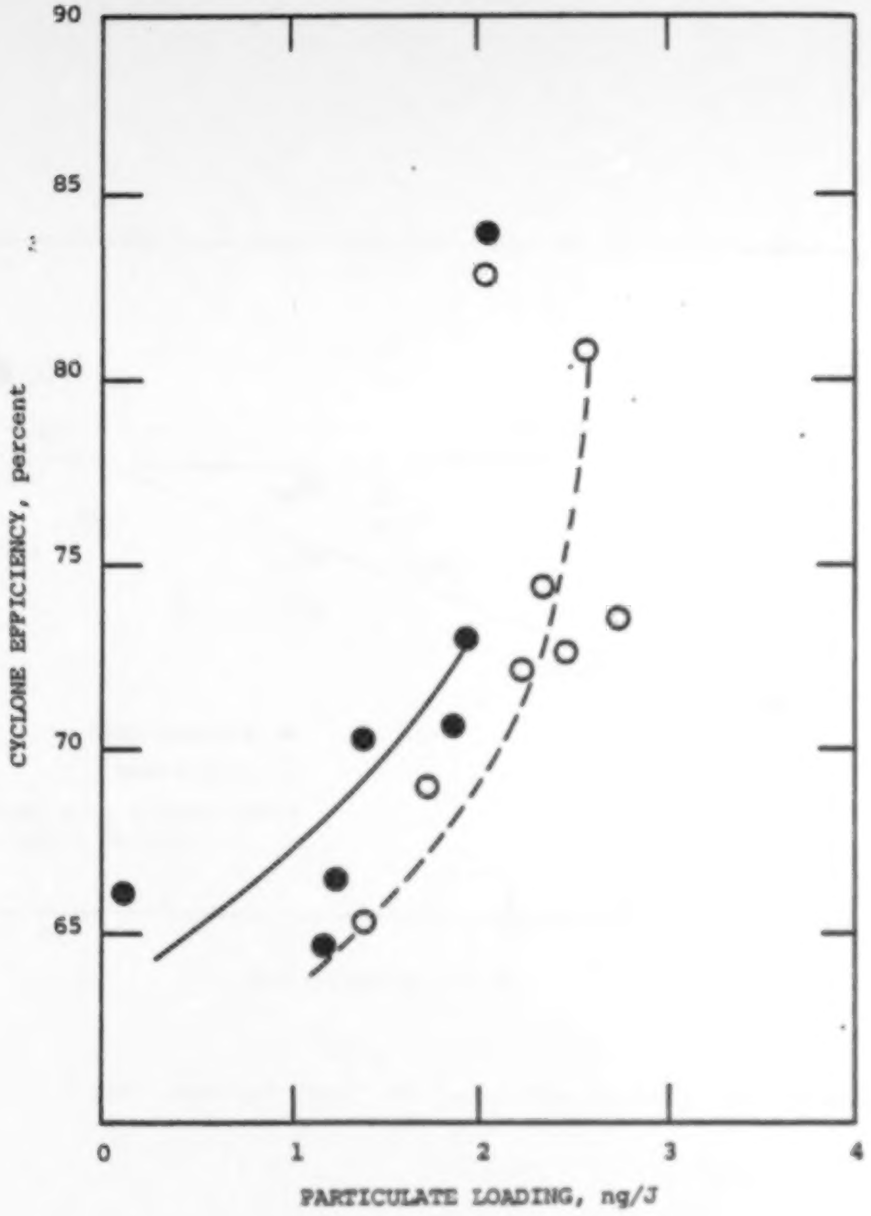


Figure 5.7-8. Cyclone efficiency vs. particulate loading, Fairmont Unit 3, eastern coal and blended coal.

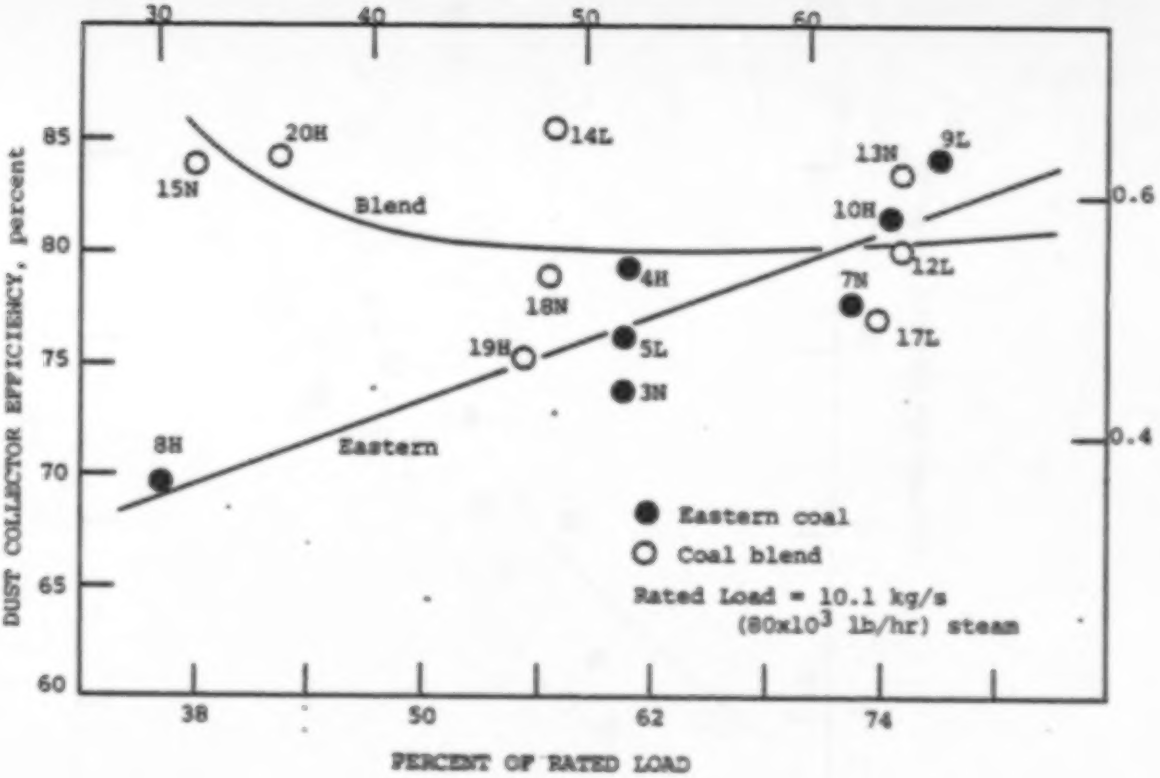


Figure 5.7-9. Cyclone efficiency vs. load, Fairmont Unit 3.

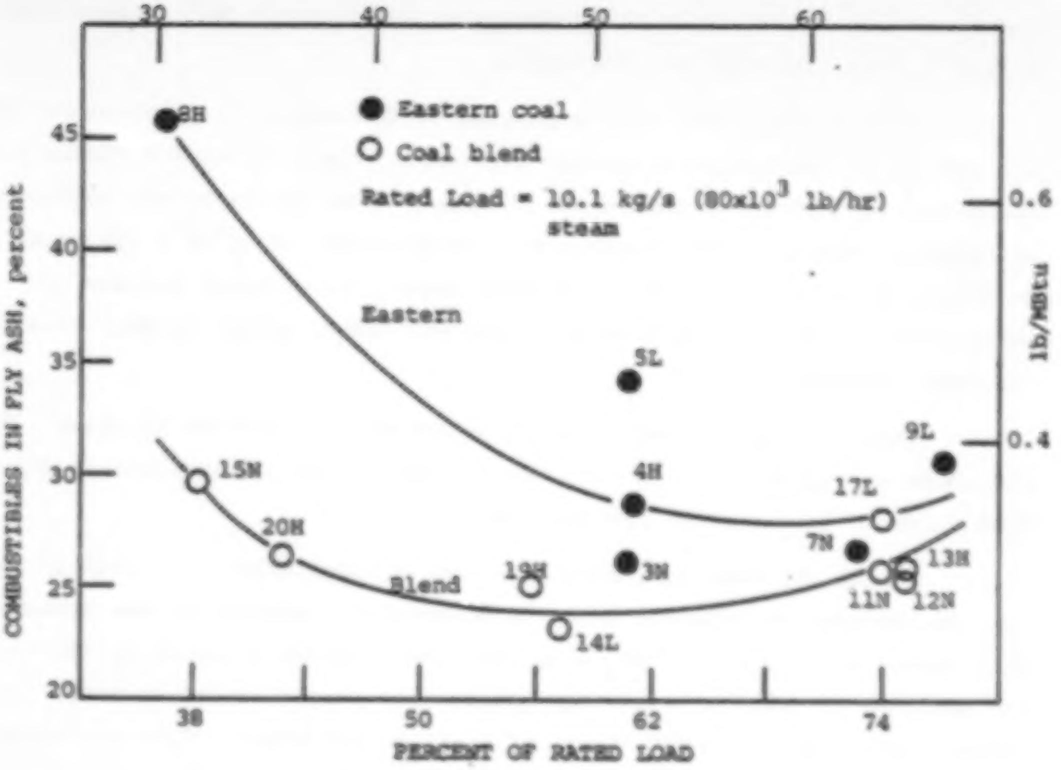


Figure 5.7-10. Percent combustibles vs. load, Fairmont Unit 3.

Table 5.7-3 summarizes the sulfur oxides data, and Figure 5.7-11 illustrates the test results for both fuels. It can be readily seen that although the blend showed an average 4.9% reduction in SOx over the eastern coal, statistically there was no significant difference between the two. It can also be seen that the SOx did not vary significantly with either load or excess O_2, the two main test variables.

Studies have shown that a portion of the sulfur is retained in the ash and is not emitted as a gaseous pollutant. Table 5.7-4 and Figure 5.7-12 illustrate an attempt to make a mass balance of sulfur-in versus sulfur-out at Fairmont Unit #3. The unaccountable differences of up to ± 15% point out deficiencies in the experimental methods used. These could include non-representative sampling of both fuel and emissions, and/or inaccuracies in the analytical method.

Despite these inconsistencies in the data, one point is clear. Sulfur retention was quite low at about 0.8% as measured in the ash, and it did not significantly vary between the two fuels.

Sulfur trioxide does sometimes show a correlation with load or excess O_2. In the case of Fairmont Unit #3, however, no correlation was found and for this reason no plot of the SO_3 data was made. Sulfur trioxide concentrations are included in Table 5.7-3. They averaged 19.6 ng/J (0.046 lb/MBtu) for the eastern coal and 21.3 ng/J 90.50 lb/MBtu) for the blend. This corresponds to 2.3% and 2.6%, respectively, of the total measured sulfur oxides.

C. Nitric Oxides--

Nitric oxide concentrations as measured at the inlet to the dust collector are tabulated in Table 5.7-5. Average concentrations between the two fuels are seen to be about the same, averaging 130 ng/J (0.30 lb/MBtu). The similarity, however, stops there. Figures 5.7-13 and 5.7-14 illustrate the variation of nitric oxide concentration with excess O_2. For eastern coal firing, a very high dependence on excess O_2 was found. This dependence appeared to increase slightly as the loads were lowered. For example, at a load of

TABLE 5.7-3. SULFUR OXIDES DATA, FAIRMONT PUBLIC UTILITIES COMMISSION, UNIT 3

Test No.	Steam Load kg/s (10^3 lb/hr)	Excess O_2 percent	Total Oxides of Sulfur			Sulfur Trioxide		
			ppm @ 3% O_2	lb/MBtu	ng/J	ppm @ 3% O_2	lb/MBtu	ng/J
1	4.0 (31.5)	12.40	1585	2.958	1272	77	0.144	61.8
2	6.1 (48.6)	9.09	1673	3.122	1342	82	0.153	65.8
4	6.2 (49.2)	10.08	1740	3.247	1396	31	0.058	24.9
5	6.1 (48.9)	8.16	1434	2.676	1151	12	0.022	9.6
7	7.4 (58.8)	7.99	1949	3.637	1564	33	0.062	26.5
8	3.6 (28.6)	13.93	1797	3.354	1442	23	0.043	18.5
9	7.9 (62.6)	6.45	1682	3.139	1350	9	0.017	7.2
10	7.6 (60.5)	9.76	1445	2.697	1159	37	0.069	29.7
Average Eastern Coal			1663	3.104	1335	38	0.071	30.5
Standard Deviation			163	0.325	140	27	0.051	22.0
11	7.6 (60.2)	6.95	1539	2.912	1252	18	0.034	14.6
12	7.7 (61.0)	6.95	1636	3.095	1331	12	0.023	9.8
14	5.8 (45.9)	8.01	1615	3.055	1314	54	0.102	43.9
15	3.8 (30.2)	12.94	1248	2.361	1015	7	0.013	5.7
16	7.1 (56.4)	8.26	1828	3.458	1487	50	0.095	40.7
17	7.6 (60.0)	6.62	1502	2.842	1222	16	0.030	13.0
18	5.8 (45.7)	9.37	1672	3.163	1360	164	0.310	133.4
19	5.5 (44.6)	12.40	1565	2.961	1273	32	0.061	26.0
20	4.3 (33.8)	14.13	1439	2.722	1170	14	0.026	11.4
Average Coal Blend			1560	2.952	1269	41	0.077	33.2
Standard Deviation			162	0.306	131	49	0.093	40.0

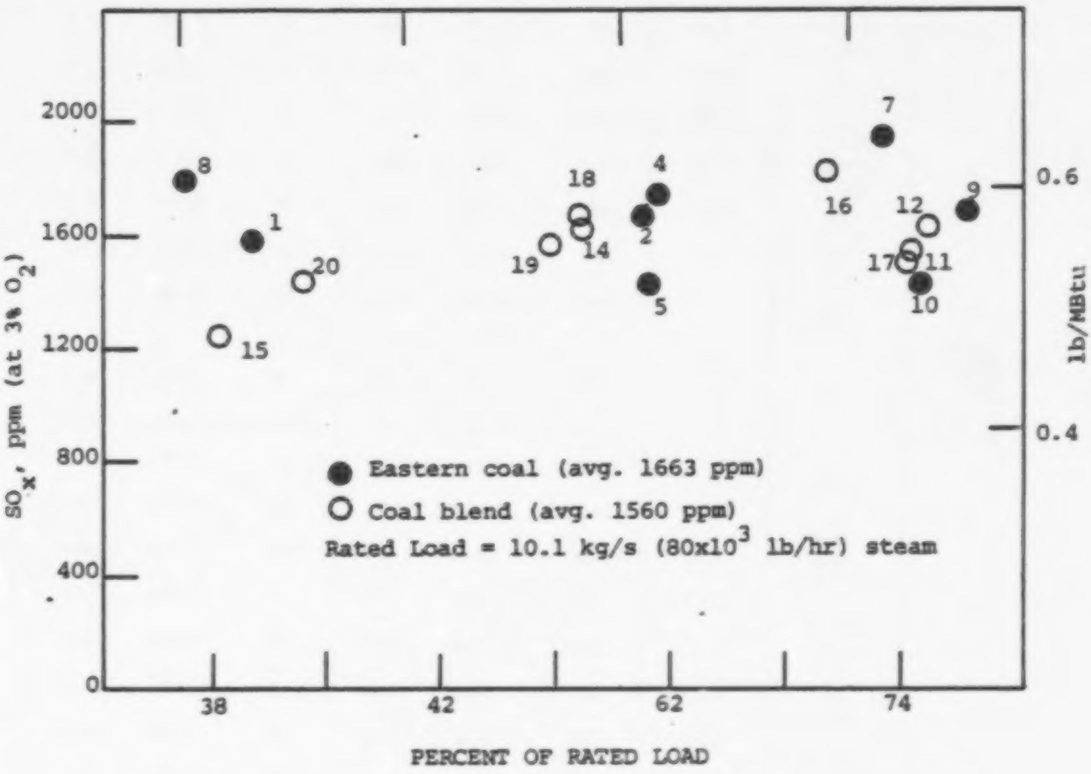


Figure 5.7-11. SO_x comparison for eastern coal vs. blend, Fairmont Unit 3.

TABLE 5.7-4. SULFUR OXIDES RETENTION IN ASH, FAIRMONT PUBLIC UTILITIES COMMISSION, UNIT 3

Test No.	Computed Sulfur Into System % S Fuel	HHV Fuel MJ/kg	SO_x ng/J	Measured Sulfur Retention Ash % of Fuel	Sulfur % of Ash	SO_x ng/J	Retention percent	Measured Emissions SO_x ng/J	Unaccounted Difference ng/J	Percent Difference
5	2.69	31.06	1732	8.85	--	--	--	1151	--	--
7	2.04	30.84	1323	8.69	--	--	--	1564	--	--
9	2.23	31.30	1425	8.11	0.28	14.6	1.03	1350	67.5	4.74
10	2.14	31.14	1374	8.41	0.11	6.0	0.44	1160	211	15.39
Average	2.28 (.29)	31.09	1463	8.52	0.20	10.3	0.74	1306	140	
12	1.74	29.60	1176	8.96	0.17	10.3	0.88	1330	160	-13.64
15	1.73	29.60	1169	8.97	0.16	9.9	0.85	1015	149	12.73
17	1.94	29.63	1309	9.69	--	--	--	1222	--	--
18	1.96	29.06	1349	8.92	--	--	--	1360	--	--
Average	1.84	29.47	1251	9.14	0.17	10.3	0.87	1232	-6.0	
Difference %	-19.0%	-5.2%	-14.5%	+7.3%	-15.4%	-4.2%	+16.4%	-5.7%		

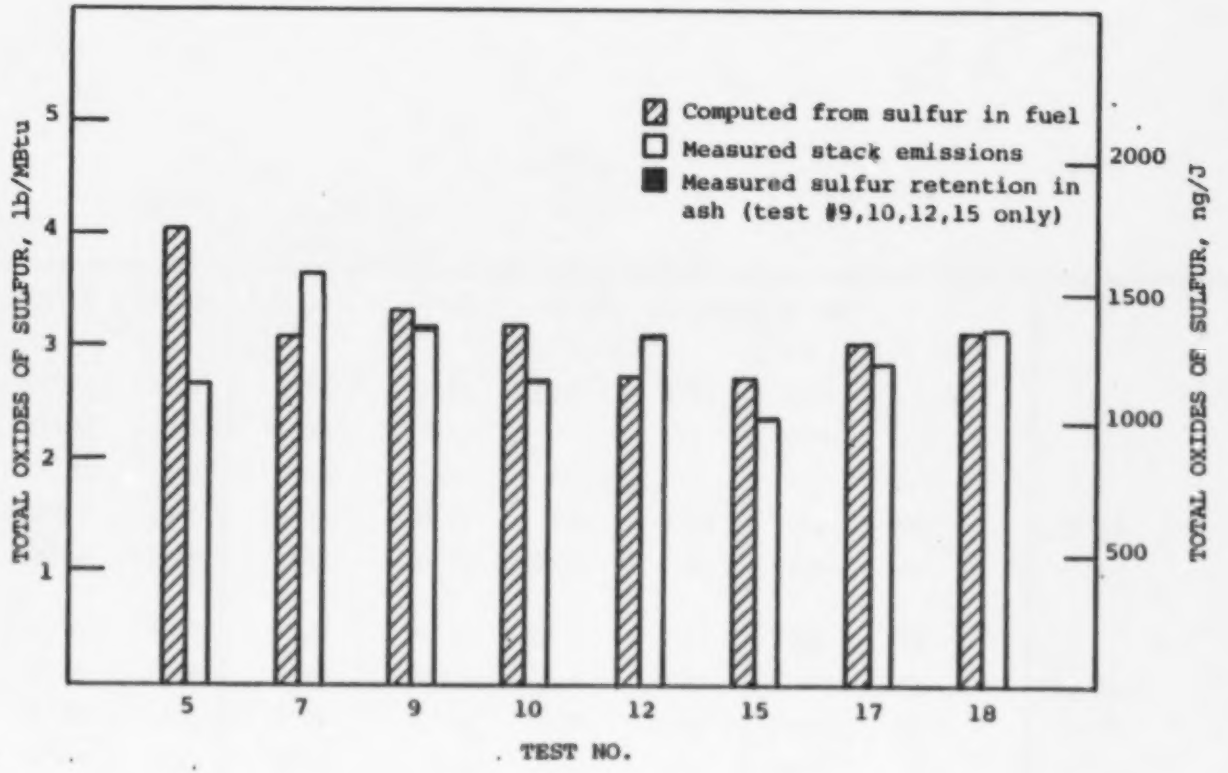


Figure 5.7-12. Sulfur mass balance, Fairmont Unit 3.

TABLE 5.7-5. NITRIC OXIDE DATA, FAIRMONT PUBLIC UTILITIES COMMISSION, UNIT 3

Test No.	Load kg/s (10^3 lb/hr)	Excess O_2 percent	Nitric Oxide Concentration		
			ppm @ 3% O_2	lb/MBtu	ng/J
1	4.6 (31.5)	12.40	311	0.272	117
2	6.1 (48.6)	9.09	333	0.291	125
3	6.2 (48.9)	9.32	320	0.280	120
4	6.1 (49.2)	10.08	388	0.339	146
5	7.4 (48.9)	8.16	265	0.232	100
6	7.2 (57.4)	8.03	391	0.342	147
7	7.4 (58.8)	7.99	313	0.274	118
8	3.6 (28.6)	13.53	422	0.369	159
9	7.9 (62.6)	6.45	282	0.247	106
10	7.6 (60.5)	9.76	411	0.359	154
Average Eastern Coal			344	0.300	129
11	7.6 (60.2)	6.95	278	0.246	106
12	7.7 (61.0)	6.95	303	0.269	115
13	7.6 (61.1)	8.06	353	0.313	134
14	5.8 (45.9)	8.01	372	0.330	142
15	3.8 (30.2)	12.94	413	0.366	157
16	7.1 (56.4)	8.26	338	0.300	129
17	7.6 (60.0)	6.62	307	0.272	117
18	5.8 (45.7)	9.37	323	0.286	123
19	5.5 (44.0)	12.40	349	0.309	133
20	4.3 (33.8)	14.13	415	0.368	158
Average Coal Blend			345	0.306	131

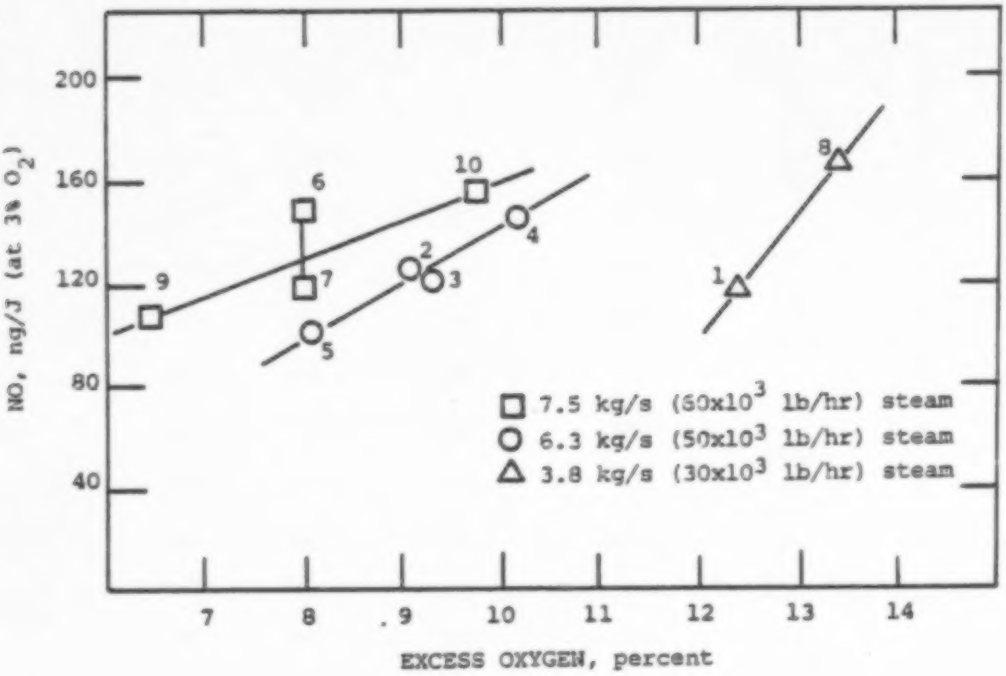


Figure 5.7-13. Nitric oxide emissions vs. excess O_2, Fairmont Unit 3, eastern coal.

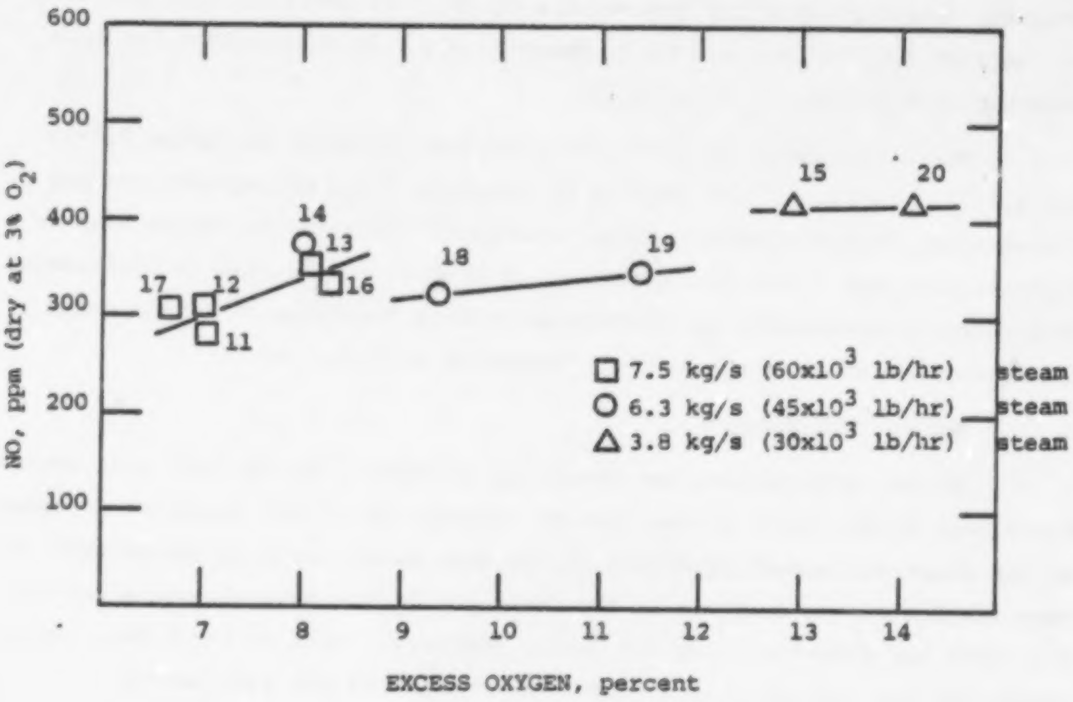


Figure 5.7-14. Nitric oxide emissions vs. excess O_2, Fairmont Unit 3, coal blend.

7.6 kg/s (60×10^3 lb/hr), NO concentration increased at a rate of 14.65 ng/J per % O_2; at 6.2 kg/s (49×10^3 lb/hr), 22.6 ng/J per % O_2; and at 3.8 kg/s (30×10^3 lb/hr), 41.72 ng/J per % O_2. For the coal blend, on the other hand, the trend was reversed with a decreasing dependence in excess O_2 as the load dropped. The corresponding figures are 15.09, 4.88 and 1.19 ng/J per % O_2 at loads of 7.6, 5.7 and 4.0 kg/s, respectively. No explanation for this behavior is attempted in this report.

The variation of nitric oxide with load is shown in Figure 5.7-15 and 5.7-16. Increased load results in increased furnace temperatures and consequently increased nitric oxide formation. However, as can be seen in Figures 5.7-4 and 5.7-5, the excess O_2 is lowered as the load is increased. This tends to counteract the temperature effect resulting in nitric oxide concentrations which are relatively invariant with the load.

D. Boiler Efficiency--

Boiler efficiencies are generally determined by the heat loss method. These heat losses occur in the form of unburned fuel such as carbon monoxide in the stack and carbon retention in the ash; endothermic processes such as vaporization of the moisture in the fuel; and direct thermal losses out of the stack and radiation from the boiler surfaces. Each of these heat losses, except for the radiation loss, may be a function of the fuel burned.

Thermal efficiency losses for several Fairmont Unit #3 tests on both coals were computed. These computations are based on the ASME abbreviated heat loss method or so-called "short form" computation from the ASME Power Test Code 4.1. The results are shown in Table 5.7-6.

Carbon monoxide emissions are plotted as a function of excess O_2 in Figure 5.7-17. It is quite obvious that the coal blend emitted more CO than did the eastern coal. It is also seen that the emissions increased at both high and low excess O_2. However, because of the interrelationship between load and O_2 (excess O_2 is higher at lower loads in stoker fired units), it is sometimes hard to determine which parameter has the most effect on emissions. In this unit, low loads and high excess O_2 created the most carbon monoxide.

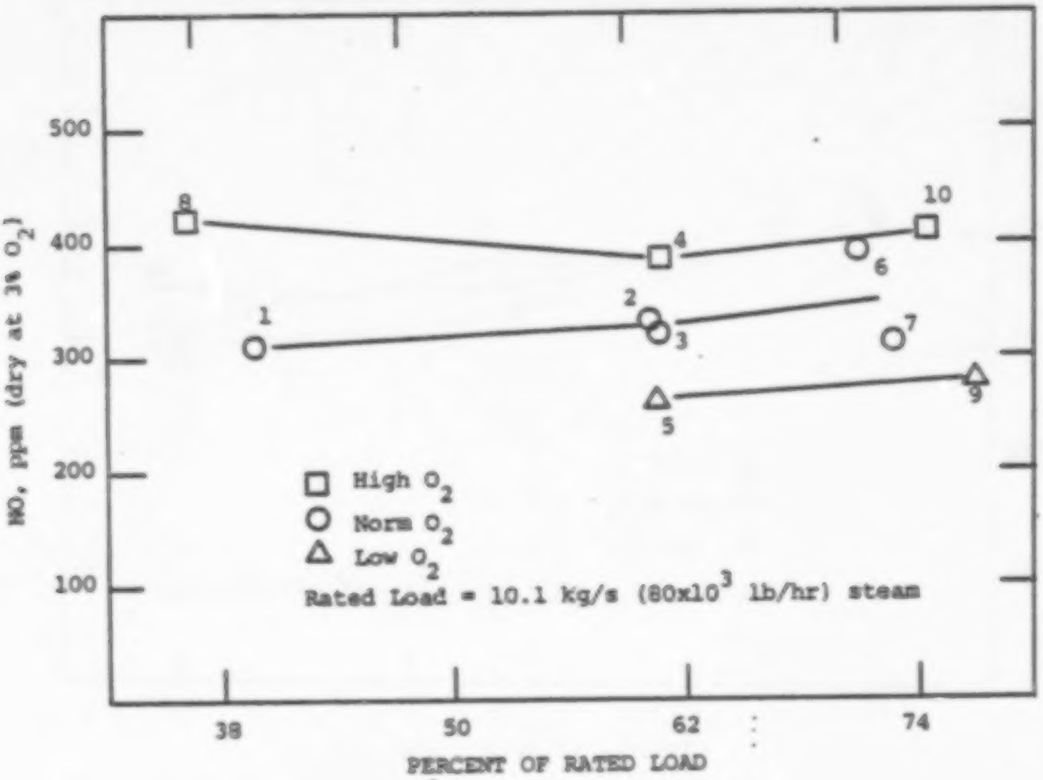


Figure 5.7-15. Nitric oxide emissions vs. load, Fairmont Unit 3, eastern coal.

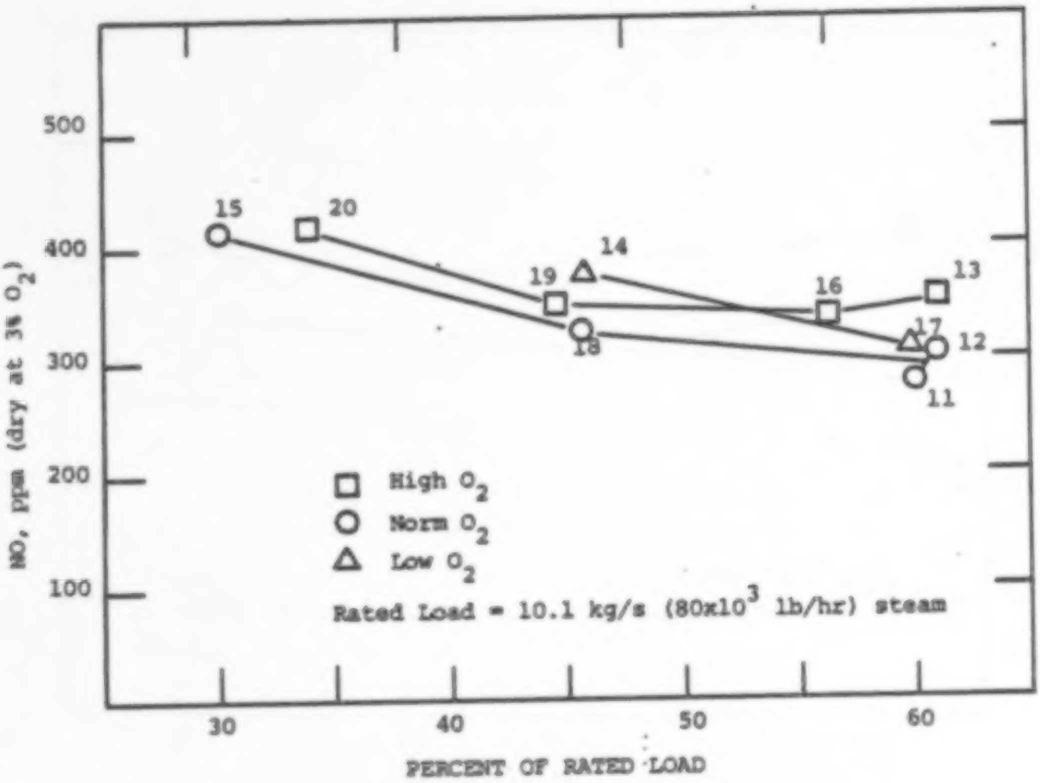


Figure 5.7-16. Nitric oxide emissions vs. load, Fairmont Unit 3, coal blend.

TABLE 5.7-6. BOILER EFFICIENCY DATA, FAIRMONT PUBLIC UTILITIES COMMISSION, UNIT 3

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                        BOILER CATEGORY  211

        DATE: 10/13/76       TIME: 14:16:36             PAGE:   1

     UNIT DESCRIPTION                        FUEL ANALYSIS
                                      NATURAL GAS          OIL OR COAL
LOCATION NO.        6                 CO2          0.     C             62.28
BOILER NO.          3                 CO           0.     H              4.21
FURNACE TYPE        WT                N2           0.     O              9.62
CAPACITY                              H2S          0.     N               .48
   10^3 lb/hr    10.1 kg/s (80.0)     CH4          0.     S              1.49
    MMBTU/HR             80.0         C2H6         0.     H2O           14.19
INSTALLED           1951              C3H8         0.     ASH            7.69
ERECTION METHOD     FIELD             C4H10        0.     HHV/(BTU/LB) 10922
BURNER TYPE         SS                C5H12        0.
                                    HHV(BTU/CUFT)     0


                             OIL OR COAL

                          BOILER CONDITIONS

TEST NO.                  12         13         14         15         17

TEST LOAD
  KLB/HR                 61.0       61.1       45.9       30.2       60.0
  % OF CAP               76.3       76.4       57.4       37.8       75.0
STACK O2 (% DRY)          7.0        8.1        8.0       12.9        6.6
STACK CO (PPM)           72.0       83.0       88.0      519.0      349.0
STACK TEMP (F)          523.0      548.0      502.0      462.0      523.0
AMB AIR TEMP (F)         84.0       84.0       86.0       85.0       87.0
CORR. STACK TEMP(F)     523.0      548.0      502.0      462.0      523.0

                   BOILER HEAT BALANCE LOSSES (%)

         HEAT BALANCE LOSSES CORRECTED TO 80.F ENTERING AIR TEMP.

DRY GAS                  12.06      13.80      12.40      17.51      11.73
MOIST + H2                6.14       6.19       6.09       6.00       6.14
MOISTURE IN AIR            .29        .33        .30        .42        .28
UNBURNED CO                .03        .04        .04        .41        .15
COMBUSTIBLES              2.61       2.67       2.30       3.23       2.99
RADIATION                  .76        .76       1.01       1.54        .77

BOILER EFFICIENCY        78.12      76.21      77.86      70.89      77.94
THERMODYNAMIC EFF.       0.         0.         0.         0.         0.
```

TABLE 5.7-6. Continued

BOILER CATEGORY 211

DATE: 10/13/76 TIME: 14:16:36 PAGE: 2

UNIT DESCRIPTION	
LOCATION NO.	7 6
BOILER NO.	3
FURNACE TYPE	WT
CAPACITY	
10^3 lb/hr	10.1 kg/s (80.0)
MBTU/HR	80.0
INSTALLED	1951
ERECTION METHOD	FIELD
BURNER TYPE	SS

FUEL ANALYSIS

NATURAL GAS		OIL OR COAL	
CO2	0.	C	62.28
CO	0.	H	4.21
N2	0.	O	9.62
H2S	0.	N	.48
CH4	0.	S	1.49
C2H6	0.	H2O	14.19
C3H8	0.	ASH	7.69
C4H10	0.	HHV/(BTU/LB)	10922
C5H12	0.		
HHV(BTU/CUFT)	0		

OIL OR COAL

BOILER CONDITIONS

TEST NO.	18	19	20
TEST LOAD			
KLB/HR	45.7	44.6	33.8
% OF CAP	57.1	55.7	42.3
STACK O2 (% DRY)	9.4	11.4	14.1
STACK CO (PPM)	165.0	189.0	805.0
STACK TEMP (F)	399.0	388.0	393.0
AMB AIR TEMP (F)	75.0	72.0	83.0
CORR. STACK TEMP(F)	399.0	388.0	393.0

BOILER HEAT BALANCE LOSSES (%)

HEAT BALANCE LOSSES CORRECTED TO 80.F ENTERING AIR TEMP.

DRY GAS	10.29	11.97	16.75
MOIST + H2	5.87	5.84	5.85
MOISTURE IN AIR	.25	.29	.41
UNBURNED CO	.09	.13	.74
COMBUSTIBLES	2.69	2.56	2.74
RADIATION	1.02	1.04	1.37
BOILER EFFICIENCY	79.80	78.17	72.14
THERMODYNAMIC EFF.	0.	0.	0.

TABLE 5.7-6. Continued

```
                    BOILER CATEGORY  211

      DATE: 10/13/76      TIME: 15:17:04            PAGE:   1

    UNIT DESCRIPTION                          FUEL ANALYSIS
                                        NATURAL GAS         OIL OR COAL
LOCATION NO.         6                CO2          0.    C            68.35
BOILER NO.           3                CO           0.    H             4.56
FURNACE TYPE         WT               N2           0.    O             7.72
CAPACITY                              H2S          0.    N             1.06
  10^3 lb/hr     10.1 kg/s (80.0)     CH4          0.    S             2.23
   MBTU/HR             134            C2H6         0.    H2O           7.84
INSTALLED            1951             C3H8         0.    ASH           8.21
ERECTION METHOD      FIELD            C4H10        0.    HHV/(BTU/LB) 12306
BURNER TYPE          SS               C5H12        0.
                                    HHV(BTU/CUFT)      0

                          OIL OR COAL

                       BOILER CONDITIONS

TEST NO.                   3          4          5          7          8

TEST LOAD
  KLB/HR                 48.9       49.2       48.9       58.8       28.6
  % OF CAP               61.1       61.5       61.1       73.5       35.8
STACK O2 (% DRY)           9.3       10.1        8.2        8.0       13.5
STACK CO (PPM)           38.0       32.0       81.0       52.0      208.0
STACK TEMP (F)          491.0      505.0      429.0      484.0      451.0
AMB AIR TEMP (F)         77.0       84.0       81.0       73.0       70.0
CORR. STACK TEMP(F)     491.0      505.0      429.0      484.0      451.0

                BOILER HEAT BALANCE LOSSES (%)

        HEAT BALANCE LOSSES CORRECTED TO 80.F ENTERING AIR TEMP.

DRY GAS                 13.13      14.45       9.99      11.62      17.48
MOIST + H2               5.05       5.07       4.94       5.04       4.98
MOISTURE IN AIR           .31        .35        .24        .28        .42
UNBURNED CO               .02        .02        .04        .03        .17
COMBUSTIBLES             2.56       2.91       3.78       2.64       6.10
RADIATION                 .95        .94        .95        .79       1.62

BOILER EFFICIENCY       77.99      76.26      80.07      79.61      69.23
```

TABLE 5.7-6. Continued

```
                         BOILER CATEGORY  211

          DATE: 10/13/76       TIME: 15:17:04              PAGE:   2

       UNIT DESCRIPTION                          FUEL ANALYSIS
                                        NATURAL GAS              OIL OR COAL
  LOCATION NO.          6              CO2           0.     C              68.35
  BOILER NO.            3              CO            0.     H               4.56
  FURNACE TYPE          WT             N2            0.     O               7.72
  CAPACITY                             H2S           0.     N               1.06
     10^3 lb/hr    10.1 kg/s (80.0)    CH4           0.     S               2.23
     MBTU/HR                 80.0      C2H6          0.     H2O             7.84
  INSTALLED             1951           C3H8          0.     ASH             8.21
  ERECTION METHOD       FIELD          C4H10         0.     HHV/(BTU/LB) 12306
  BURNER TYPE           SS             C5H12         0.
                                     HHV(BTU/CUFT)      0

                             OIL OR COAL

                           BOILER CONDITIONS

  TEST NO.                   9          10
  TEST LOAD
    KLB/HR                  62.6        60.5
    % OF CAP                78.2        75.6
  STACK O2 (% DRY)           6.5         9.8
  STACK CO (PPM)           155.0        81.0
  STACK TEMP (F)           486.0       493.0
  AMB AIR TEMP (F)          65.0        66.0
  CORR. STACK TEMP(F)      486.0       493.0

                    BOILER HEAT BALANCE LOSSES (%)

         HEAT BALANCE LOSSES CORRECTED TO 80.F ENTERING AIR TEMP.

  DRY GAS                  10.43       13.61
  MOIST + HR                5.04        5.05
  MOISTURE IN AIR            .25         .33
  UNBURNED CO                .07         .04
  COMBUSTIBLES              3.19        3.11
  RADIATION                  .74         .77

  BOILER EFFICIENCY        80.29       77.09
  THERMODYNAMIC EFF.        0.          0.
```

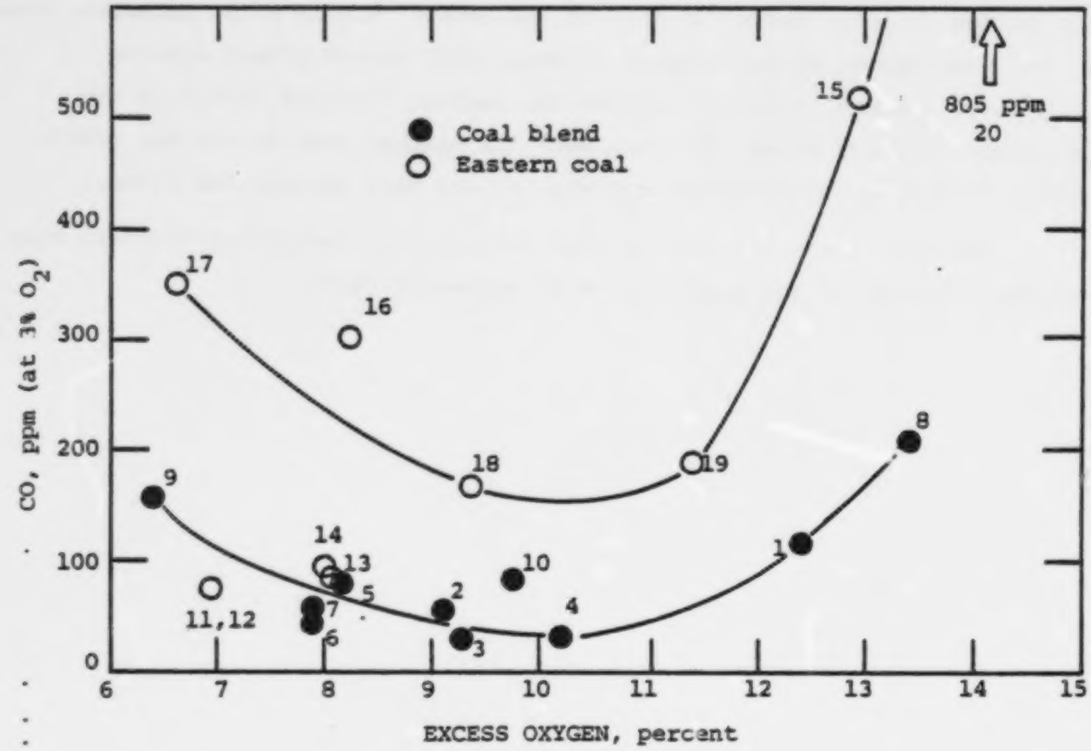


Figure 5.7-17. CO comparison for eastern coal vs. blend, Fairmont Unit 3.

E. Emissions Summary--

The emissions in brief are as follows. Particulates met applicable regulations with both fuels,although the blend emitted 33% more than the eastern coal. Sulfur oxides were basically unchanged at 1300 ng/J (3.0 lb/MBtu), with sulfur trioxide making up 2.5% of the total. Nitric oxide emissions were basically unchanged on the average although they showed a much greater dependence on excess O_2 while burning the eastern coal and therefore the lowest nitric oxide emissions found were for eastern coal at minimum excess oxygen. And, combustion efficiency was reduced when burning the blend.

The conclusion can only be that burning this particular blend in this particular boiler is not justified on an emissions basis.

5.8 WAUPUN CENTRAL GENERATING PLANT, UNIT #3, WAUPUN, WISCONSIN

Densified Refuse-Derived Fuel (d-RDF) was blended directly with coal and successfully fired in a spreader stoker fired water tube boiler without boiler modification. Twenty percent and thirty percent d-RDF blend, computed on a Btu basis, were successfully fired while a 40% blend firing failed due to excessive clinker formation on the grate. Particulate, nitric oxide and carbon monoxide emissions were found to be unaffected by the addition of d-RDF. Sulfur oxide emissions were reduced.

5.8.1 Introduction

The testing conducted at Waupun Central Generating Plant (CGP) represents an important deviation from the mainstream of the Western Coal Project. Instead of evaluating western coal combustion against a base line eastern coal, a refuse derived fuel was evaluated as a fuel supplement against a base line western coal.

The importance of such an evaluation is easily seen. With dwindling fossil fuel reserves and increasing solid waste disposal problems, the successful demonstration of a refuse-derived fuel supplement could lead to a significant improvement in our energy situation. As an added benefit, these refuse-derived fuels are usually very low in sulfur thus reducing sulfur oxide emissions.

It has been said that boilers can be designed to burn any fuel. Of more importance in this case are the following questions. How can refuse derived fuels be made to burn in existing boilers? To what extent can the normal fuel (usually coal) be supplemented with this fuel? To answer these questions the Wisconsin Solid Waste Recycling Aughority in cooperation with other state and private agencies tested several state-owned boilers with a densified Refuse-Derived Fuel (d-RDF).

KVB, Inc. was invited to participate in the data-taking at the CGP, Waupun State Prison, for the purposes of this report. Credit is due OSM, Inc. and the various Wisconsin state agencies for organizing and conducting the testing, and to the Wisconsin Division of Natural Resources for supplying us with the particulate data taken during the actual d-RDF firing.

5.8.2 Boiler Description

The boiler tested was Unit 3 at the Waupun Central Generating Plant, Waupun, Wisconsin. This unit consists of a four drum, bent tube boiler manufactured by Wickes Boiler Company and installed in 1948. It is fired by two Riley Corporation spreader stokers feeding a hydraulically operated traveling grate. The furnace is a balanced draft unit and the furnace pressure is maintained at -20 cm H_2O. Induced draft (ID) and forced draft (FD) fans were supplied by the Clarage Fan Company. The boiler design capacity is 3.8 kg/s (30,000 lb/hr steam flow). This unit has twelve overfire air ports, four on each side wall and four on the back wall of the furnace. An interesting feature of this unit is that the overfire air is preheated before entering the furnace.

After combustion, the hot flue gases pass upward in the boiler through a superheater section. Day-to-day operating data indicates an outlet steam pressure of 3.0 MPa (425 psig) and steam temperature of 650 °K (710 °F). The unit does not have steam attemperation. After passing the superheater section, the hot gases cross a short section of water tubes connecting the lower drum to the chemical drum and then enter the cyclone dust collector. Fly ash captured in the cyclone is returned to the grate ash hopper under the boiler. Originally the ash from the cyclone was reinjected into the furnace, but, the reinjection was eliminated several years ago. The flue gas is finally pulled through the ID fan and exhausted into a breeching (shared by other boilers at the facility) that leads to the smokestack.

The role of the Waupun CGP is to provide power to the adjacent Wisconsin State Prison and the nearby state hospital. Very significantly, Waupun CGP has no tie-in with outside power sources. As a result, special precautions were required during testing which resulted in inconveniences which will be described later.

5.8.3 Sample Locations

The facility at Waupun CGP consists of three identical coal-fired boilers and one gas-fired boiler connected to a single stack by a common manifold. Figure 5.8-1 is a schematic of the facility.

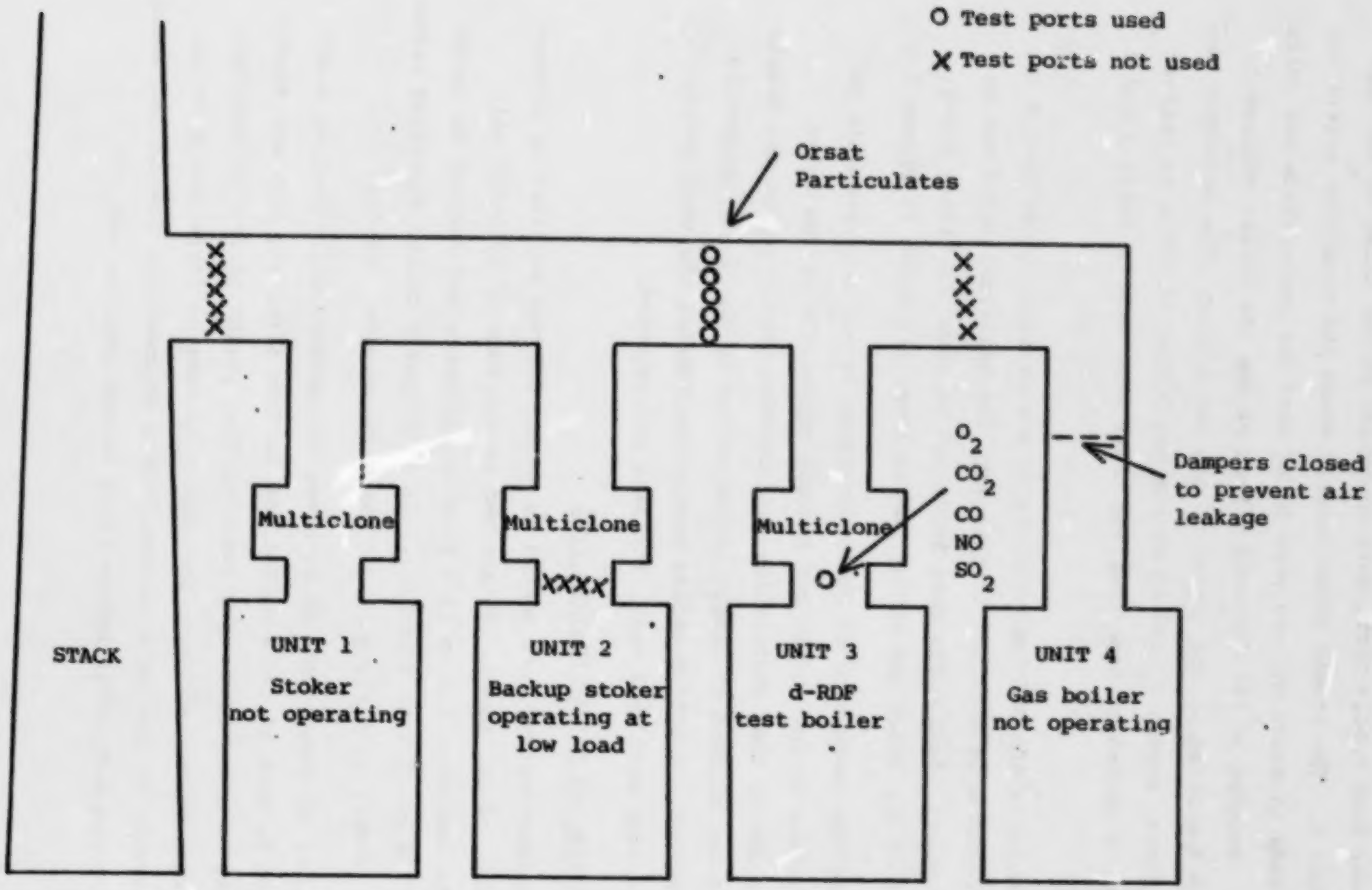

O Test ports used
X Test ports not used
Orsat
Particulates
Dampers closed
to prevent air
leakage
STACK
Multiclone
Multiclone
Multiclone
UNIT 1
Stoker
not operating
UNIT 2
Backup stoker
operating at
low load
UNIT 3
d-RDF
test boiler
UNIT 4
Gas boiler
not operating
O2
CO2
CO
NO
SO2

Figure 5.8-1. Schematic of boilers and flue gas duct system, Waupun, Wisconsin.

The initial plan was to test Unit 2 using the gas boiler as a backup. For this purpose, four sample ports were installed at the inlet to the dust collector on Unit 2. The sample ports located where the breeching enters the stack were already in existence and were to be used for particulate and sulfur oxide testing. Because of the dilution effect of the gas boiler effluents, four ports were installed at the outlet of the gas boiler. The objective was to sample gas flows, excess O_2 and CO at the gas boiler in order to correct the stack data. A series of nine complete tests were made on Units 2 and 4 in this manner.

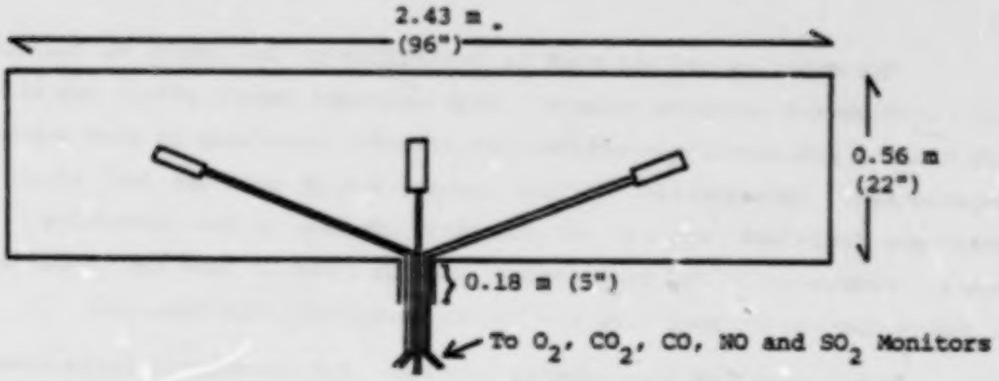
Just prior to the RDF test burning it was decided to use Unit 3 for the tests with Unit 2 as backup. In this way, the emissions would not be subject to dilution. Test ports were installed as shown in Figure 5.8-1. Cross sections of the inlet and outlet sample areas are shown in Figure 5.8-2.

Because the tests were of short duration; it was only possible to sample particulates at the outlet and gaseous components at the inlet. Unfortunately, due to time restrictions and crowded conditions at the sample areas, KVB was not allowed to sample sulfur oxides by the Shell-Emeryville wet chemical method. A sulfur oxides continuous monitor was used instead, but due to problems with this unit, its data was rejected.

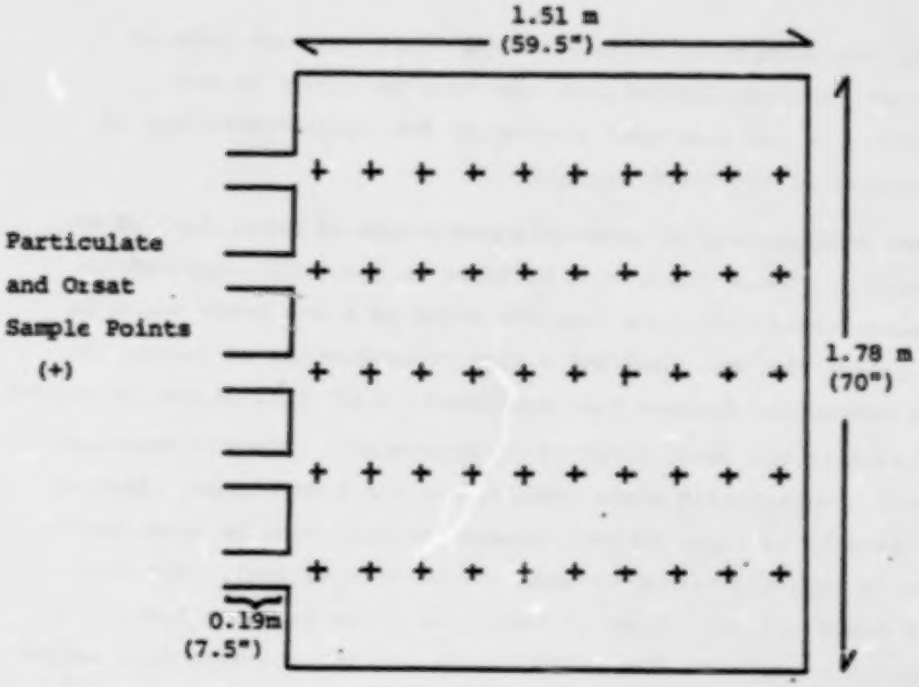
5.8.4 Discussion of Refuse-Derived Fuel

The refuse-derived fuel tested at Waupun CGP was supplied by Grumman Ecosystems, Inc. of St. Louis. It arrived in the form of cylindrically shaped pellets measuring 1.9 cm (3/4 inch) in diameter and varying in length from 1.27 to 7.5 cm (1/2 to 3 inches). It is properly called densified refuse derived fuel (d-RDF) to distinguish it from the shredded variety.

In order to understand the problems encountered while burning d-RDF in Waupun Unit 3, some of the fuel related factors affecting spreader stoker operation must be understood. For example, fuel pellet sizing is important. It must be sized to mix well with the coal. It must be large enough to be distributed evenly on the grate without piling up under the feeders yet small enough to burn out completely before being dumped into the ash pit.


2.43 m
(96")
0.56 m
(22")
0.18 m (5")
To O_2, CO_2, CO, NO and SO_2 Monitors

DUST COLLECTOR INLET


1.51 m
(59.5")
Particulate
and Orsat
Sample Points
(+)
1.78 m
(70")
0.19m
(7.5")

DUST COLLECTOR OUTLET

Figure 5.8-2. Sample area geometry, Waupun Unit 3.

The moisture content must be controlled to low levels to facilitate easy ignition and complete burnout. High moisture levels affect the distribution of radiant-to-convective heat transfer resulting in high superheat temperatures. Consequently, boilers burning a high moisture fuel often experience decreased capacity and slagging problems in the convective passes. Increased ID fan requirements may also result from the requirement to remove the water vapor from the boiler along with the flue gas.

Ash properties pose another problem. Refuse-derived fuels often contain large concentrations of chloride compounds which are very corrosive. This disadvantage is partially offset by their inherently low sulfur content. Also, ash fusion temperatures have been reported to be very low resulting in clinker problems on the grate and fouling in the convective passes.

The high ash content of refuse-derived fuels can mean reduced capacity due to ash handling limitations, and more man-hours in ash pulling operations. It can also mean greater FD fan requirements due to the higher resistance of the thick ash bed.

Spreader stokers rely on a certain percentage of their fuel to be burned in suspension. Since there were no fines in the d-RDF supplied to Waupun, fuel blends containing more than 50% d-RDF on a Btu basis would be unsatisfactory unless the coal used had a high concentration of fines. In addition to the combustion factors just mentioned, d-RDF fuel cannot be stored unprotected outside as can coal, since it is hygroscopic (absorbs moisture). When this happens, it literally comes unglued and can't be burned. Each of these factors, as well as other as yet unknown factors, must be considered when converting an existing boiler to burn refuse-derived fuel. The fuel analysis of the d-RDF and coal fired at Waupun is given in Table 5.8-1. It can be noted that the sulfur in the d-RDF is low (0.22%) and even on a weight of equivalent SO_2 per unit heating value it is low at 300 ng/J (0.7 lb/10^6 Btu). The fuel nitrogen in the d-RDF is high on a heating value basis but not as high as it was in some of the coals burned in this program. Certainly the heating value of the d-RDF is high enough to warrant handling and limited shipping of this fuel.

TABLE 5.8-1. COMPARISON OF TEST FUELS FIRED AT WAUPUN UNIT 3

DENSIFIED REFUSE-DERIVED FUEL Grumman Ecosystems, St. Louis			**WESTERN COAL** Colstrip, Montana		
PROXIMATE ANALYSIS	As Received	Dry Basis	PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	4.33	xxxxx	% Moisture	10.88	xxxxx
% Ash	30.49	31.87	% Ash	10.55	11.84
% Volatile	54.34	56.80	% Volatile	35.44	39.76
% Fixed Carbon	10.84	11.33	% Fixed Carbon	43.13	48.40
	100.00	100.00		100.00	100.00
High Htg Value, MJ/kg	14.3	14.9	High Htg Value, MJ/kg	22.8	25.5
Btu/lb	6161	6440	Btu/lb	9791	10986
% Sulfur	0.22	0.23	% Sulfur	0.93	1.04
% Alk. as Na_2O	xxxxx	2.33	% Alk. as Na_2O	xxxxx	0.06
SULFUR FORMS			SULFUR FORMS		
% Pyritic Sulfur	*	*	% Pyritic Sulfur	0.50	0.56
% Sulfate Sulfur	0.00	0.00	% Sulfate Sulfur	0.13	0.15
% Organic Sulfur	*	*	% Organic Sulfur	0.30	0.33
% Total Sulfur	0.22	0.23	% Total Sulfur	0.93	1.04

ULTIMATE ANALYSIS	% Weight As Received	Dry Basis	ULTIMATE ANALYSIS	% Weight As Received	Dry Basis
Moisture	4.33	xxxxx	Moisture	10.88	xxxxx
Carbon	34.31	35.86	Carbon	58.16	65.26
Hydrogen	4.59	4.80	Hydrogen	3.86	4.33
Nitrogen	0.57	0.60	Nitrogen	0.48	0.54
Chlorine	0.54	0.56	Chlorine	0.01	0.01
Sulfur	0.22	0.23	Sulfur	0.93	1.04
Ash	30.49	31.87	Ash	10.55	11.84
Oxygen (diff)	24.95	26.08	Oxygen (diff)	15.13	16.98
	100.00	100.00		100.00	100.00

MINERAL ANALYSIS	% Weight Ignited Basis	MINERAL ANALYSIS	% Weight Ignited Basis
Phos. pentoxide, P_2O_5	0.70	Phos. pentoxide, P_2O_5	0.16
Silica, SiO_2	59.41	Silica, SiO_2	33.42
Ferric oxide, Fe_2O_3	5.88	Ferric oxide, Fe_2O_3	7.76
Alumina, Al_2O_3	9.07	Alumina, Al_2O_3	16.24
Titania, TiO_2	1.05	Titania, TiO_2	0.71
Lime, CaO	11.67	Lime, CaO	20.30
Magnesia, MgO	1.66	Magnesia, MgO	4.22
Sulfur trioxide, SO_3	2.23	Sulfur trioxide, SO_3	15.26
Potassium oxide, K_2O	1.95	Potassium oxide, K_2O	0.48
Sodium oxide, Na_2O	6.04	Sodium oxide, Na_2O	0.52
Undetermined	0.34	Undetermined	0.93
	100.00		100.00

Silica Value = 75.57 T250 = 2415 °F (1597 °K)		Silica Value = 50.86 T250 = 2220 °F (1489 °K)	
FUSION TEMPERATURE OF ASH	Reducing	FUSION TEMPERATURE OF ASH	Reducing
Initial Deformation	1930 °F (1328 °K)	Initial Deformation	2100 °F (1422 °K)
Softening (H=W)	2025 °F (1380 °K)	Softening (H=W)	2130 °F (1439 °K)
Softening (H=1/2W)	2120 °F (1433 °K)	Softening (H=1/2W)	2160 °F (1455 °K)
Fluid	2215 °F (1485 °K)	Fluid	2180 °F (1467 °K)
(H = cone height; W = cone width)		(H = cone height; W = cone width)	

*Unable to determine
Standard method not applicable

5.8.5 Fuel Blending

The d-RDF was transported from St. Louis to Waupun by truck and piled in an open area outside the plant. To protect it from the weather, the pile was covered with large plastic sheets.

Mixing was accomplished with a front-end loader. Buckets of each fuel were alternately dumped into the freight car unloading hopper in a predetermined ratio as outlined in Table 5.8-2. Mixing was accomplished at the various transfer points as the fuel was transported to live storage.

The 20% and 40% mixtures were prepared the day before actual firing. The 30% blend was accomplished by alternately feeding the previously mixed 40% blend into the feeder hopper for 90 seconds followed by 30 seconds of pure western coal. This procedure was continued until all of the 40% blend was mixed.

TABLE 5.8-2. FUEL MIXING SCHEDULE, WAUPUN UNIT 3

d-RDF	14.3 MJ/kg (6161 Btu/lb)	0.761 g/cm^3 (47.5 lb/ft^3)	10,900 J/cm^3 (292,648 Btu/ft^3)
Coal	22.8 MJ/kg (9791 Btu/lb)	0.785 g/cm^3 (49 lb/ft^3)	17,273 J/cm^3 (479,759 Btu/ft^3)

20% BLEND (26.3% d-RDF by volume; 17.9% d-RDF on Btu basis)

10 parts d-RDF + 28 parts coal by volume
= 16,035 J/cm^3 (430,519 Btu/ft^3)
= 20.6 MJ/kg (8,840 Btu/lb) assuming 0.780 g/cm^3 (48.7 lb/ft^3)

40% BLEND (50.0% d-RDF by volume; 37.9% d-RDF on Btu basis)

20 parts d-RDF + 20 parts coal by volume
= 14,384 J/cm^3 (386,203 Btu/ft^3)
= 18.6 MJ/kg (7,979 Btu/lb) assuming 0.775 g/cm^3 (48.4 lb/ft^3)

30% BLEND (37.5% d-RDF by volume; 26.8% d-RDF on Btu basis)

3 parts 40% mixture + 1 part coal by volume
= 15,256 J/cm^3 (409,592 Btu/ft^3)
= 19.6 MJ/kg (8,436 Btu/lb) assuming 0.778 g/cm^3 (48.55 lb/ft^3)

As can be seen, our computations show that the actual mixture contained less d-RDF on a BTU basis than the test labels (i.e., 20, 30 and 40%) indicate. Nevertheless, the labels will be used throughout this report.

A problem was encountered in blending the d-RDF. As the mixture traveled down the chute towards the spreaders, the less dense d-RDF pellets tended to move towards the sides of the chute. This segregation of the fuels may have contributed to the clinkering problem. It is suggested that smaller sized d-RDF pellets might blend more easily with the coal.

5.8.6 Control Room Observations

The following observations were made during the actual test firing. It should be noted that the "average load" was computed by dividing the steam flow integrator readings by the time between readings. A summary of the more important operating variables is given at the end of this section.

TEST #1, 20% d-RDF, JUNE 3, 1976

The first test was for a mixture containing 20% d-RDF and 80% Western coal on a BTU basis. The duration of the test was 5 1/2 hours. The mixture, having been fed into the bunker, was not expected to reach the feeders until about 9:00 am. To everyone's surprise, the pellets were first observed on the grate at about 8:15 am. It was estimated that the actual start was at 8:00 am.

There were no immediate problems or obvious changes in boiler operation at transition. The first indication of transition to the d-RDF blend was the visual observance of pellets on the grate. The d-RDF ash retained its form and appeared to "float" on top of the ash bed. These ash pellets fell apart when picked up and appeared to be nearly if not completely burned out.

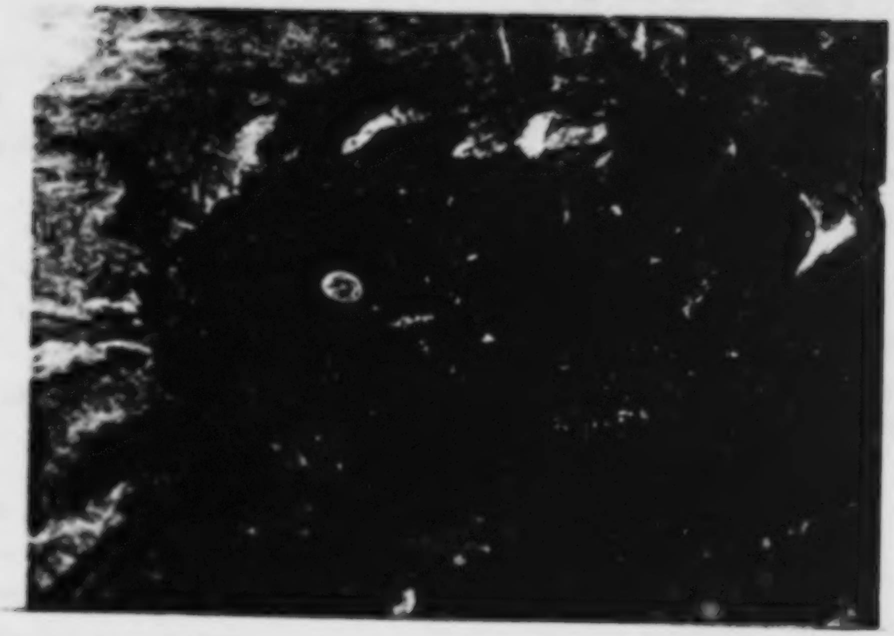


Figure 5.8-3. Photograph of a 30% d-RDF blend as fired at Waupun.

As the burning progressed, the ash bed began to thicken. To keep the bed thickness within limits, the grate speed was increased gradually throughout the run from three to six (relative numbers on the grate speed control). Despite this increase in grate speed, the ash bed increased in thickness to 6-8 cm (2-1/2 - 3 inches). On pure western coal, the ash bed is 4-5 cm (1-1/2 - 2 inches) thick.

At 9:40 am, a problem with clinkers developed. It appeared that the d-RDF was piling up in front of the feeders. At 10:45, the spill plates (trajectory plates) were pulled back 1 cm (3/8 inch) in an attempt to throw the coal and pellets further back on the grate. Immediately after this change, the load dropped from its peak of 3.1 kg/s ($24x10^3$lb/hr) to 2.3 kg/s ($18x10^3$ lb/hr) due to lunch break at the prison. Fuel distribution on the grate appeared to improve with the spill plate adjustment and clinker problems were moderate for the duration of this run.

Smoke remained at 11% on the opacity meter throughout this run. This is the same as for pure western coal under the same load condition. Average load for this test was 2.8 kg/s (22,500 lb/hr) steam.

TEST #2, 40% d-RDF, JUNE 3, 1976

When the fuel from test #1 had burned down to the windows just above the feeders, a d-RDF/coal blend containing 40% d-RDF on a Btu basis was added to the bunker. Transition to the new blend occurred at 1:30 p.m.

The grate speed was increased in steps from 6 to 8.2 to handle the increased ash. At 2:10 p.m. clinkering became moderate. By 2:34 p.m. a massive coal pile covered the entire front of the grate riding on top of a very large clinker. Carbon monoxide was rising out of limits (2000^+ ppm) and smoke was increasing (25%). By 3:00 p.m. the clinker problem became severe. The pile under the feeders was so high you couldn't see into the boiler through the ash doors. The pile covered the full width of the boiler, extended four to five feet back from the front wall and was about one foot thick.

Luckily, only a small amount of the 40% mixture had been put in the bunker and transition to 100% western coal was made at 3:20 p.m. Duration of this test was one hour, fifty minutes. Average load was 2.9 kg/s (22,900 lb/hr) steam.

TEST #3, 100% WESTERN COAL, JUNE 4, 1976

In order to obtain base line data on Unit 3, pure western coal was burned long enough to allow the Wisconsin DNR to get particulate data at the multiclone outlet and KVB to get control room data and gaseous emissions data at the multiclone inlet.

Burning was routine with no clinker problems. Ash was completely burned out, grate speed was set at 2.8 and spill plates were set at 5 cm (2 inches). Ash bed was 4 cm (1-1/2 inches) thick and smoke varied from 10-12% opacity.

Testing commenced at 8:30 a.m. and terminated at 10:20 a.m. Duration of this test was one hour, fifty minutes. Average load was 2.77 kg/s (22,000 lb/hr) steam.

TEST #4, 30% d-RDF, JUNE 4, 1976

A 30% d-RDF mixture was obtained by feeding the previously mixed 40% d-RDF mixture into a bunker for 90 seconds followed by 30 seconds of pure western coal. This procedure was continued until all of the 40% blend was mixed.

Based on the previous day's experience, the spill plates (stoker trajectory plates) were set back to 4.75 cm (1-7/8 inches) and the grate speed increased from 2.8 to 5.6 (relative indication on control device) immediately upon transition. The combustion air was raised considerably over what it had been during the previous d-RDF burns.

The flame appeared to become more luminous. The flame front became more irregular but moved forward about half a foot. This may have been partly due to increased grate speed. Flame impingement on the back wall also increased. At 11:15 a.m. the load dropped drastically to about 1.25 kg/s (10,000 lb/hr) steam, then oscillated back and forth around 1.9 kg/s (15,000 lb/hr) steam. It appeared to be an automatic control problem which overcorrected for the noon time drop in load.

One very large clinker formed and was removed at 12:30 p.m. This was the only major problem with the 30% blend. Testing started at 10:20 a.m. and concluded at 1:00 p.m. Duration of test was two hours and forty minutes. Average load was 2.2 kg/s (17,600 lb/hr) steam.

SUMMARY OF OPERATING VARIABLES

Some of the more important operating variables are given in Table 5.8-3 below. The first nine items are used in boiler efficiency calculations discussed in Section 5.8.9. # steam/# fuel, or evaporation as it is commonly called, is an average for each test excluding the transition period when most of the stoker adjustments were made. Smoke (%) indicates the extremes for the three or four readings taken off the opacity meter each test. Grate speed is a relative indication on the control device. The numbers shown represent the final setting for that test. Spill plate (trajectory plate) setting is relative. The lower numbers indicate the plate was pulled back in an attempt to throw the fuel further back on the grate.

TABLE 5.8-3. OPERATING VARIABLES, WAUPUN UNIT 3

	0% RDF	20% RDF	30% RDF	40% RDF
Feedwater Temperature, °K	425	426	428	427
°F	305	306	310	308
Steam Temperature, °K	652	650	646	656
°F	713	710	703	720
Steam Pressure, Pa	3.03×10^6	3.01×10^6	3.03×10^6	3.02×10^6
psig	425	422	425	423
Steam Flow, 10^3 lb/hr	22.0	22.5	17.6	22.9
Heating Rate, kg/s	13.5	13.8	10.8	14.0
FD Fan Inlet Temperature, °K	303	303	305	306
°F	86	85	89	90
Relative Humidity at FD Fan, %	55	40	37	33
Flue Gas Temp., Boiler Outlet, °K	608	--	604	618
°F	635	--	627	652
Excess O_2, Boiler Outlet, %	9.75	9.25	11.0	8.63
Carbon Monoxide, Boiler Outlet, ppm	589	510	818	2450
Evaporation, # steam/# coal or Kg steam/Kg coal	5.68	4.99	4.84	4.22
Smoke, % Opacity	10-12%	11%	10-11%	13-25%
Grate Speed, Relative	2.8	6.0	6.6	8.2
Spill Plate Position, Relative	5.08 cm (2")	4.76 cm (1-7/8")	4.76 cm (1-7/8")	4.76 cm (1-7/8")

The demonstration burning at Waupun CGP was of too short a duration for the operators to become thoroughly familiar with the new fuel. Had more time been available stoker controls could have been optimized and many of the clinkering problems reduced. The operators now feel that more undergrate air would have helped.

5.8.7 Particulate Emissions

Particulates were measured at the dust collector outlet as described in Section 5.8.3. The actual sampling was conducted by the Wisconsin DNP, while the computations were made by KVB, Inc. based on our own fuel analysis.

The data, Table 5.8-4, shows that particulate emissions remained relatively stable until the 40% blend was fired. At this point, emissions doubled. This doubling of emissions was probably due to the ashes being stirred up while trying to break up and remove clinkers forming on the grate.

TABLE 5.8-4. PARTICULATE EMISSIONS FROM WAUPUN UNIT 3

Blend	Average Load			Concentration	Emissions	Emissions
% d-RDF	kg/s	10^3 lb/hr	O_2, %	lb/scfx10^{-4}	lb/MBtu	ng/J
0%	2.74	22.0	9.73	0.282	0.520	224
20%	2.83	22.5	9.59	0.319	0.576	248
30%	2.22	17.6	11.53	0.206	0.446	192
40%	2.89	22.9	10.50	0.577	1.122	482

Figure 5.8-4 illustrates the particulate emissions as a function of fuel blend. The slight drop in emissions during the 30% blend firing is due to the lower boiler load during this test. To illustrate this point, the d-RDF test data is plotted against load along with the base line data obtained from Unit #2 on Figure 5.8-5 (see Section 5.8.3 for explanation of Unit #2 base line testing). Because the two units are identical, they should have the same characteristic emissions plot. As can be seen, only the 40% blend was out of line.

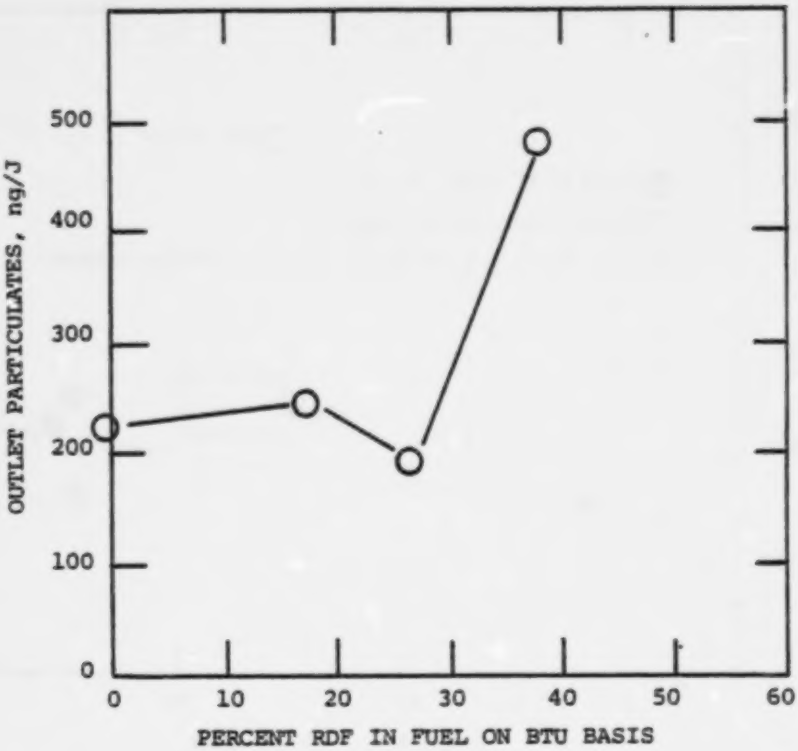


Figure 5.8-4. Particulates vs. fuel mixture, Waupun Unit 3.

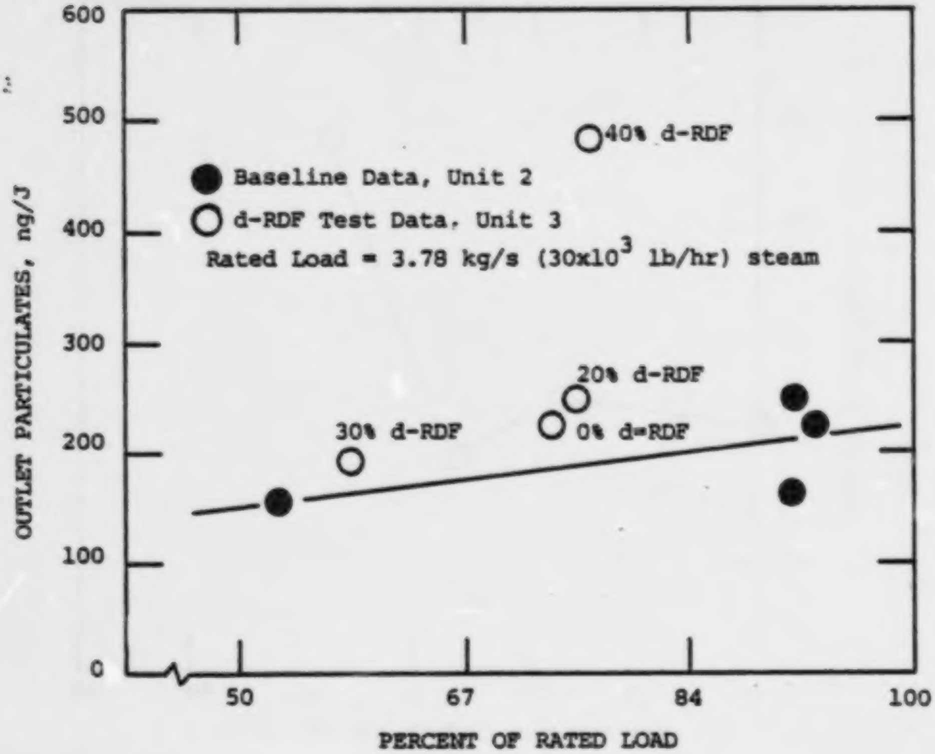


Figure 5.8-5. Outlet particulates vs. boiler load, Waupun Unit 3.

5.8.8 Gaseous Emissions

Gaseous emissions were measured at the boiler outlet just before the dust collector as shown in Figures 5.8-1 and 5.8-2. They included excess O_2, CO_2, CO, and NO. The data represents average emissions over the most stable portion of each test, usually covering a one hour period. The data is tabulated in Table 5.8-5.

TABLE 5.8-5. GASEOUS EMISSIONS, WAUPUN UNIT 3

	0% d-RDF	20% d-RDF	30% d-RDF	40% d-RDF
O_2, %	9.75	9.25	11.00	8.63
CO_2, %	10.00	10.40	8.40	11.10
$CO_2 + O_2$, %	19.75	19.65	19.40	19.73
CO, ppm @ 3% O_2	589	510	818	2450
NO, ppm @ 3% O_2	266	247	273	205
NO, lb/MBtu	0.226	0.219	0.241	0.180
NO, ng/J	97	94	103	77

In a spreader stoker, excess air requirements normally drop with increasing load. The characteristic excess O_2 versus load curve for Unit 2 was determined with the base line tests as explained in Section 5.8.3. It is plotted in Figure 5.8-6 along with the d-RDF test series data. Unit 3, being identical to Unit 2, would be expected to have a similar characteristic plot. The dashed line through the 0% d-RDF test point represents this expected plot. Based on this curve, the 40% blend, and to a lesser extent the 20% blend, were low in air. Probably the extra thickness of the RDF ash bed restricted air flow through the grate. For the 30% blend firing, a conscious effort was made by the operators to increase grate air. Their effort appears to have been successful and the result was a more uniform fire with only minor clinkering.

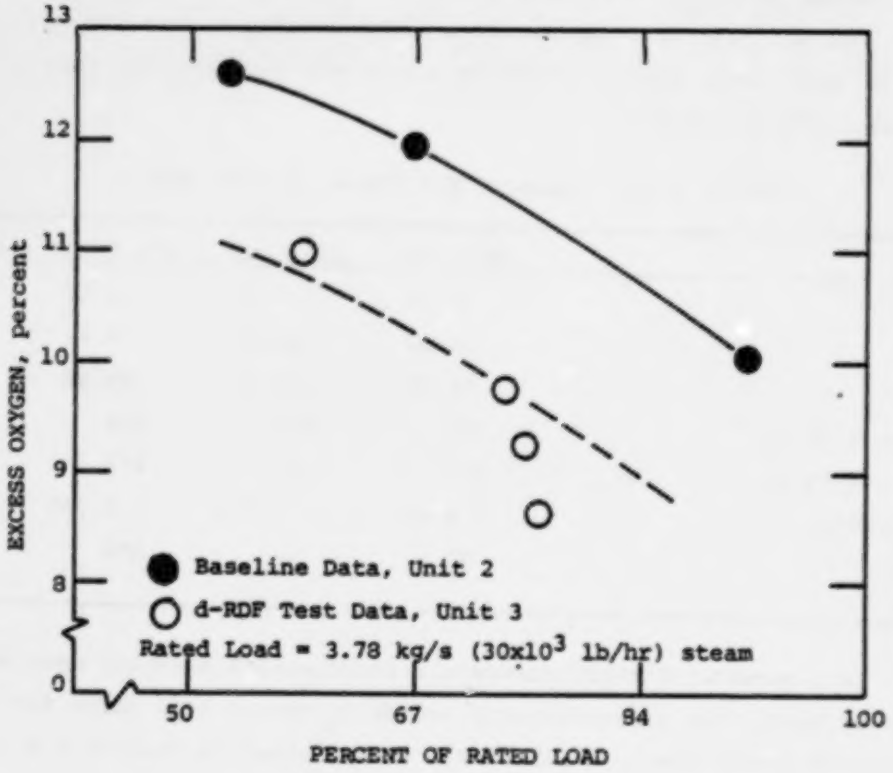


Figure 5.8-6. Excess O_2 vs. load, Waupun Unit 3.

Carbon monoxide did not vary from the norm except as a result of excessive clinker formation during the 40% blend firing. In Figure 5.8-7, carbon monoxide is plotted against load and compared with the base line data obtained from Unit 2. The numbers, except for the 40% blend, are in good agreement.

Nitric oxide emissions dropped during the 40% blend firing because of the lower furnace temperatures and the lower excess O_2. During the 30% blend test they were higher because of the higher excess O_2. This dependence on excess O_2 is normal. There is no indication that blending of d-RDF with the coal affected nitric oxide emissions except in the already mentioned case of the 40% blend where, due to poor combustion conditions, the NO emissions were reduced. Figure 5.8-8 illustrates the dependence of nitric oxide emissions on excess O_2.

The results of the sulfur oxide tests were inconclusive. Normally, sulfur oxides are measured quite accurately with the Shell-Emeryville wet chemical method. Unfortunately, this could not be fit into the already cramped test schedule. Instead, measurements were made with a continuous SO_2 monitor built by Theta Sensors with which we were having calibration problems. We believe that the instrument was sensitive to changes in emissions levels but low in absolute value.

The 0% and 30% blends were both monitored for SO_2 on the same day without changing the zero and span settings on the monitor. Based on this data, the reduction in SO_2 emissions for the 30% blend firing was 31%. This is about double the 15% reduction in fuel sulfur on a Btu basis.

A more accurate indication of sulfur oxide emissions in this case is obtained from the fuel and grate ash analysis. Table 5.8-6 represents a sulfur balance on the various d-RDF tests with sulfur oxide emissions determined by the difference between fuel sulfur and sulfur retention in the ash. Figure 5.8-9 graphically represents this data. The data shows that an 18.8% reduction in sulfur emissions could be realized by blending 30% d-RDF in with the Montana coal.

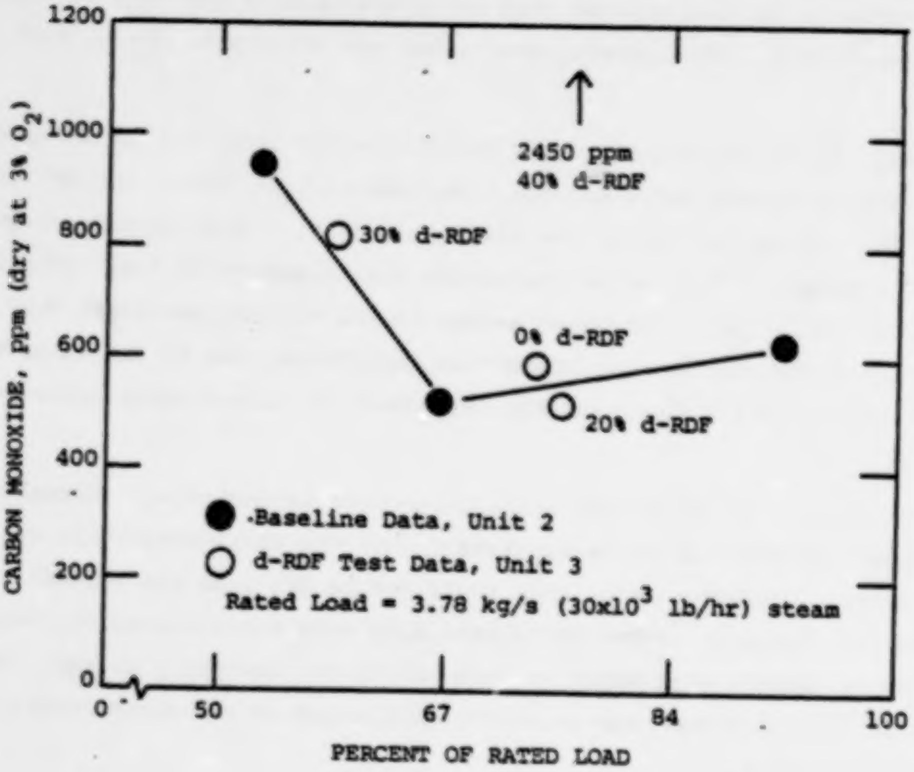


Figure 5.8-7. Carbon monoxide vs. load, Waupun Unit 3.

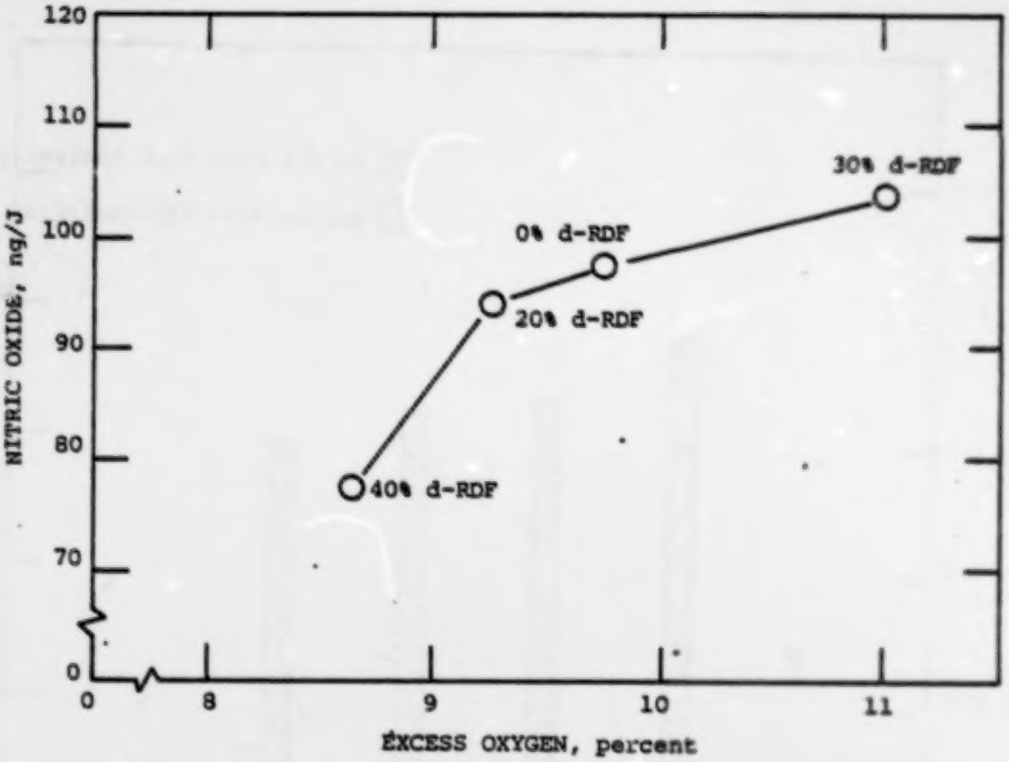


Figure 5.8-8. Nitric oxide vs. excess O_2, Waupun Unit 3.

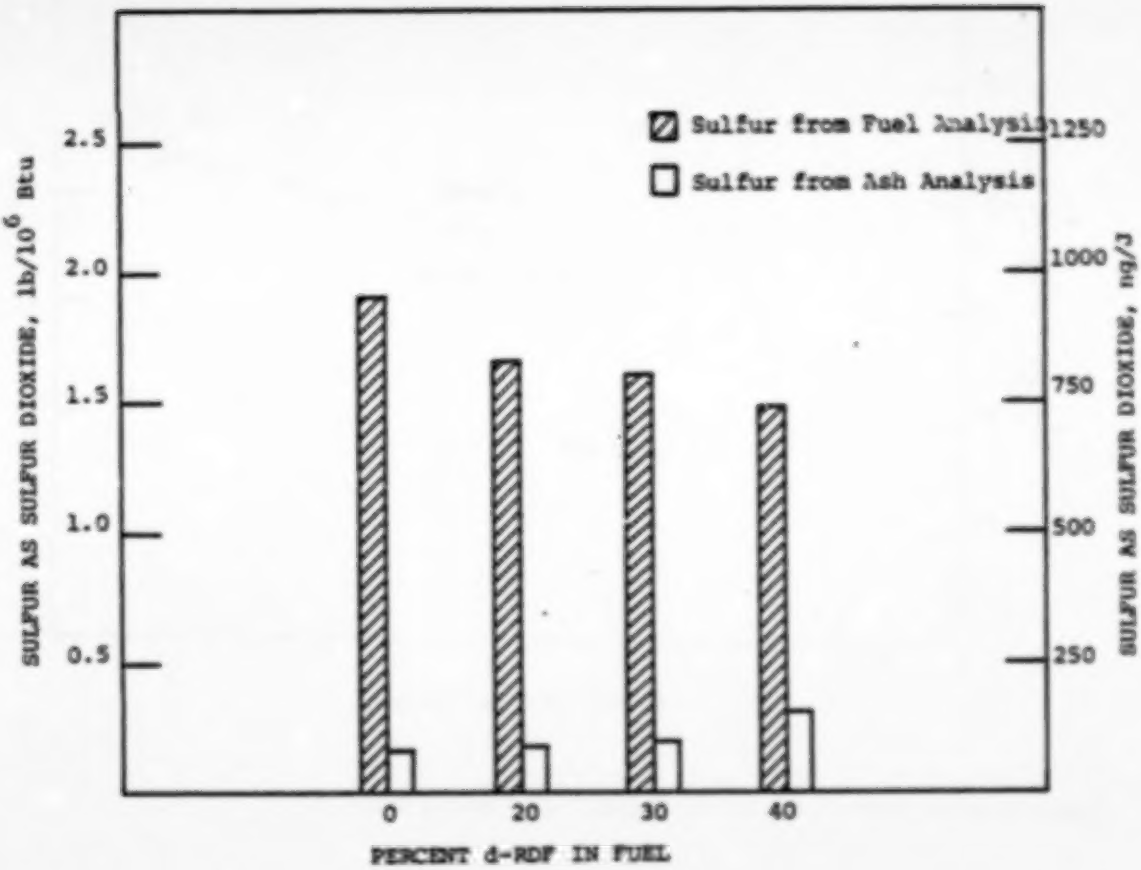


Figure 5.8-9. Sulfur in fuel and grate ash vs. fuel blend, Waupun Unit 3.

The sulfur retained in the ash is especially significant. It is shown to increase with the % d-RDF blended in the fuel. This is probably due to the alkalinity of the d-RDF ash. Basic (alkali) ashes retain more sulfur oxides than neutral or acidic ashes. Table 5.8-1 shows the sodium oxide (Na_2O) content of the d-RDF ash to be 6.04%. This is over ten times the 0.52% Na_2O found in the western coal ash. Sodium oxide is the most basic of most common ash components in coal.

TABLE 5.8-6. SULFUR OXIDES BALANCE, WAUPUN UNIT 3

Fuel Blend % d-RDF	Fuel Sulfur As SO_2, lb/10^6 Btu	Ash Sulfur As SO_2, lb/10^6 Btu	Calculated Emissions SO_2, ng/J (lb/10^6 Btu)	Sulfur Retention in Ash, %
0%	1.900	0.153	751 (1.747)	8.1
20%	1.652	0.170	637 (1.482)	10.3
30%	1.612	0.193	610 (1.419)	12.0
40%	1.479	0.307	504 (1.172)	20.8

5.8.10 Conclusions

1. A coal refuse blend containing 30% d-RDF has been successfully fired in Waupun Unit 3 for a short period of time without boiler modification.
2. Long term tests are required to assess any fouling tendencies, corrosion effects, or ash removal problems, and to further refine the stoker adjustments to minimize clinker formation.
3. Measured pollutant emissions were not adversely affected by the fuel blending. Nitric oxide, carbon monoxide and particulate emissions were unchanged for mixtures of up to 30% d-RDF. Sulfur oxides are expected to decrease although further testing is required to confirm this.
4. When firing d-RDF, more undergrate air is required due to the resistance of the thicker ash bed.
5. Because of the thicker ash bed from firing d-RDF, faster grate speeds are required to keep ash buildup to a minimum.
6. Adjustment of the stoker spill plate is necessary to distribute the fuel further back on the grate when firing d-RDF.
7. Smaller d-RDF pellets should be tried for improved blending and improved distribution on the grate.

The overall conclusion is that the tests were successful. We feel that enough was learned to proceed with a longer term test. Such a test would be required to fully assess the operating and environmental effects of burning densified refuse derived fuel in spreader stokers of this type.

5.9 ST. JOHN'S CENTRAL GENERATING PLANT UNIT #2, ST. JOHN'S ABBEY, COLLEGEVILLE, MN

An eastern coal and a western coal were burned in a 1.7 kg/s (13,500 lb/hr) steam water-walled steam generating unit equipped with two Riley spreader stokers and a split dumping grate. Both fuels could be burned equally well without clinker or smoke problems, and without capacity limitation. The western coal emitted lower particulates and lower nitric oxide emissions. Carbon monoxide emissions were unchanged, and the western coal emitted greater concentrations of sulfur oxides and hydrocarbons. Overfire air was found to effect only the nitric oxide emissions which it increased slightly. An ash balance was made on the system.

5.9.1 Introduction

The testing conducted at St. John's Unit #2 was unique in two ways. First, this boiler was the smallest in the test series having a capacity of only 1.7 kg/s (13,500 lb/hr steam) continuous load. Secondly, this was the only boiler tested in the series having a dumping grate.

This particular ash handling system allowed the weighing of ash produced from a given amount of coal and allowed an ash balance to be made on the system. Section 6.0 is devoted to this topic.

The eastern coal upon which the baseline tests were conducted was also unique. It had an unusually low sulfur content of only 0.58%. This coal was of unknown origin. It had been sitting outside for ten years, ever since the facility had switched to a western coal as its primary fuel. The present power plant superintendent had not ordered it and could find no records on it.

The eastern coal had a lower sulfur level than the western coal. This is probably due to the fact that the coal was stored outdoors for ten years. During this time the insoluble pyritic sulfur was probably air oxidized to soluble sulfate sulfur and leached out as sulfuric acid or sulfate salts. This is supported by the low pyritic sulfur concentration found in the analysis. A complete analysis of the two coals is given in Table 5.9-1. Testing took place between 6/10/76 and 7/8/76.

TABLE 5.9-1. COMPARISON OF TEST COALS, ST. JOHN'S UNIT 2

WESTERN COAL
Bighorn, Wyoming

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	15.77	—
% Ash	5.14	6.10
% Volatile	37.52	44.54
% Fixed Carbon	41.57	49.36
	100.00	100.00
High Htg Value, MJ/kg	24.5	29.0
Btu/lb	10515	12484
% Sulfur	0.61	0.73
% Alk. as Na_2O	—	0.17
SULFUR FORMS		
% Pyritic Sulfur	0.24	0.29
% Sulfate Sulfur	0.00	0.00
% Organic Sulfur	0.37	0.44
% Total Sulfur	0.61	0.73

	% Weight	
ULTIMATE ANALYSIS	As Received	Dry Basis
Moisture	15.77	--
Carbon	59.95	71.18
Hydrogen	4.26	5.06
Nitrogen	0.81	0.96
Chlorine	0.01	0.01
Sulfur	0.61	0.73
Ash	5.14	6.10
Oxygen (diff)	13.45	15.96
	100.00	100.00

MINERAL ANALYSIS	% Weight Ignited Basis
Phos.pentoxide, P_2O_5	1.09
Silica, SiO_2	35.19
Ferric oxide, Fe_2O_3	6.36
Alumina, Al_2O_3	18.89
Titania, TiO_2	1.15
Lime, CaO	14.85
Magnesia, MgO	4.36
Sulfur trioxide, SO_3	14.20
Potassium oxide, K_2O	0.66
Sodium oxide, Na_2O	2.28
Undetermined	0.97
	100.00

Silica Value = 57.91
T250 = 1525°K (2285°F)

FUSION TEMPERATURE OF ASH	Reducing
Initial Deformation	1400°K(2060°F)
Softening (H=W)	1439°K(2130°F)
Softening (H=1/2W)	1478°K(2200°F)
Fluid	1522°K(2280°F)

(H = cone height;
W = cone width)

EASTERN COAL
Origin Unknown

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture	5.18	—
% Ash	5.29	5.58
% Volatile	35.58	37.52
% Fixed Carbon	53.95	56.90
	100.00	100.00
High Htg Value, MJ/kg	30.5	32.2
Btu/lb	13123	13840
% Sulfur	0.58	0.61
% Alk. as Na_2O	--	0.08
SULFUR FORMS		
% Pyritic Sulfur	0.09	0.09
% Sulfate Sulfur	0.00	0.00
% Organic Sulfur	0.49	0.51
% Total Sulfur	0.58	0.60

	% Weight	
ULTIMATE ANALYSIS	As Received	Dry Basis
Moisture	5.18	—
Carbon	72.26	76.21
Hydrogen	5.17	5.45
Nitrogen	0.95	1.00
Chlorine	0.03	0.03
Sulfur	0.58	0.61
Ash	5.29	5.58
Oxygen (diff)	10.54	11.12
	100.00	100.00

MINERAL ANALYSIS	% Weight Ignited Basis
Phos.pentoxide, P_2O_5	0.43
Silica, SiO_2	50.23
Ferric oxide, Fe_2O_3	8.11
Alumina, Al_2O_3	28.60
Titania, TiO_2	2.03
Lime, CaO	3.60
Magnesia, MgO	1.47
Sulfur trioxide, SO_3	4.18
Potassium oxide, K_2O	1.13
Sodium oxide, Na_2O	0.71
Undetermined	0.49
	100.00

Silica Value = 79.21
T250 = 1772°K (2730°F)

FUSION TEMPERATURE OF ASH	Reducing
Initial Deformation	1533°K(2300°F)
Softening (H=W)	1592°K(2405°F)
Softening (H=1/2W)	1656°K(2520°F)
Fluid	1719°K(2635°F)

(H = cone height;
W = cone width)

5.9.2 Boiler Description

The boiler tested was Unit #2 at St. John's Abbey, Collegeville, Minnesota. It is a Keeler C.P. water-walled steam generating unit of the forced draft type with a motor-driven forced draft fan and a draft naturally induced by the stack. The unit was installed in 1945 with a Detroit single retort underfeed stoker. This stoker was replaced in 1958 with a Riley spreader stoker having two Model "B" feeders and a steam operated split dumping grate. The dumping cycle is discussed in more detail in Section 5.9.6.

The unit does not have a mechanical dust collector. Cinders settling in the back pass are picked up by an aspirator and reinjected into the furnace through four cinder return tubes located 38.1 cm (15") above the grate along the back furnace wall. Overfire air is injected through fire tubes along the back wall 45.7 cm (18") above the grate. Forced air from the same fan which supplies the overfire air and cinder return is used to cool the "air swept cut-off plate" on each of the feeders.

Coal is manually weighed and dumped into the feeder hopper with an overhead coal scale having a 454 Kg (1000 lb) capacity. This scale travels on overhead rails to feed all three of the small boilers.

The following design specifications apply to Unit #2:

Max. Continuous Load	1.7 kg/s (13,500 lb/hr steam)
Peak Load	1.9 kg/s (15,000 lb/hr steam)
Feed Water Temperature	373 °K (212°F)
Operating Pressure	1.48 MPa (200 psi)
Heating Surface	209 m^2 (2,250 sq.ft)
Grate Area	4.27 m^2 (45 sq.ft)
Furnace Volume	13.88 m^3 (490 cu.ft)
Stack Height	33 m (174.5 ft)
Stack Inside Diameter at Top	152 cm (60 in.)

The following approximate analyses were specified for this boiler by the E&A contractor when the spreader stoker was installed:

Moisture Content	5%
Volatile Matter	38.7%
Fixed Carbon	49.8%
Ash	6.5%
High Heating Value, as fired	30.2 MJ/kg (13,000 Btu/lb)
Ash Fusion Temperature	1478°K (2,200°F)
Sizing	3.2 cm x 0 cm to 1.27 cm x 0 cm (1-1/4" x 0" to 1/2" x 0") with less than 40% passing through 0.635 cm (1/4") round mesh screen

5.9.3 Sample Location

St. John's Unit #2 is one of three identical boilers connected to the smoke stack by a common breeching. A fourth boiler of identical construction but of three times the capacity is connected to the stack by a separate duct. A schematic of the three small boilers and the flue gas duct system is shown in Figure 5.9-1.

Because the unit had no mechanical dust collector, only one particulate sample location was necessary. The physical layout of the duct system restricted that sample location to the one shown in Figure 5.9-1. Most of the gaseous samples were taken from this location although late in the series, two gaseous probes were inserted into the back of the boiler just before the breeching to check the left to right fuel air balance of the stoker.

The sample area selected was not ideal for particulate sampling. Due to its proximity to a 90° bend in the flue gas stream it contained turbulence and negative velocity regions. A traverse of the area with a pitot tube gave the profile shown in Figure 5.9-2. Particulates were only sampled in the positive velocity regions. Gaseous probes were centered in each of the upper four ports. The bottom port was unusable because the bottom of the breaching was filled with flyash.

Because of the turbulence, the magnitude of the particulate numbers could suffer some accuracy. However, they should accurately portray the effects of load, excess O_2 and fuel properties on particulate emissions from this unit.

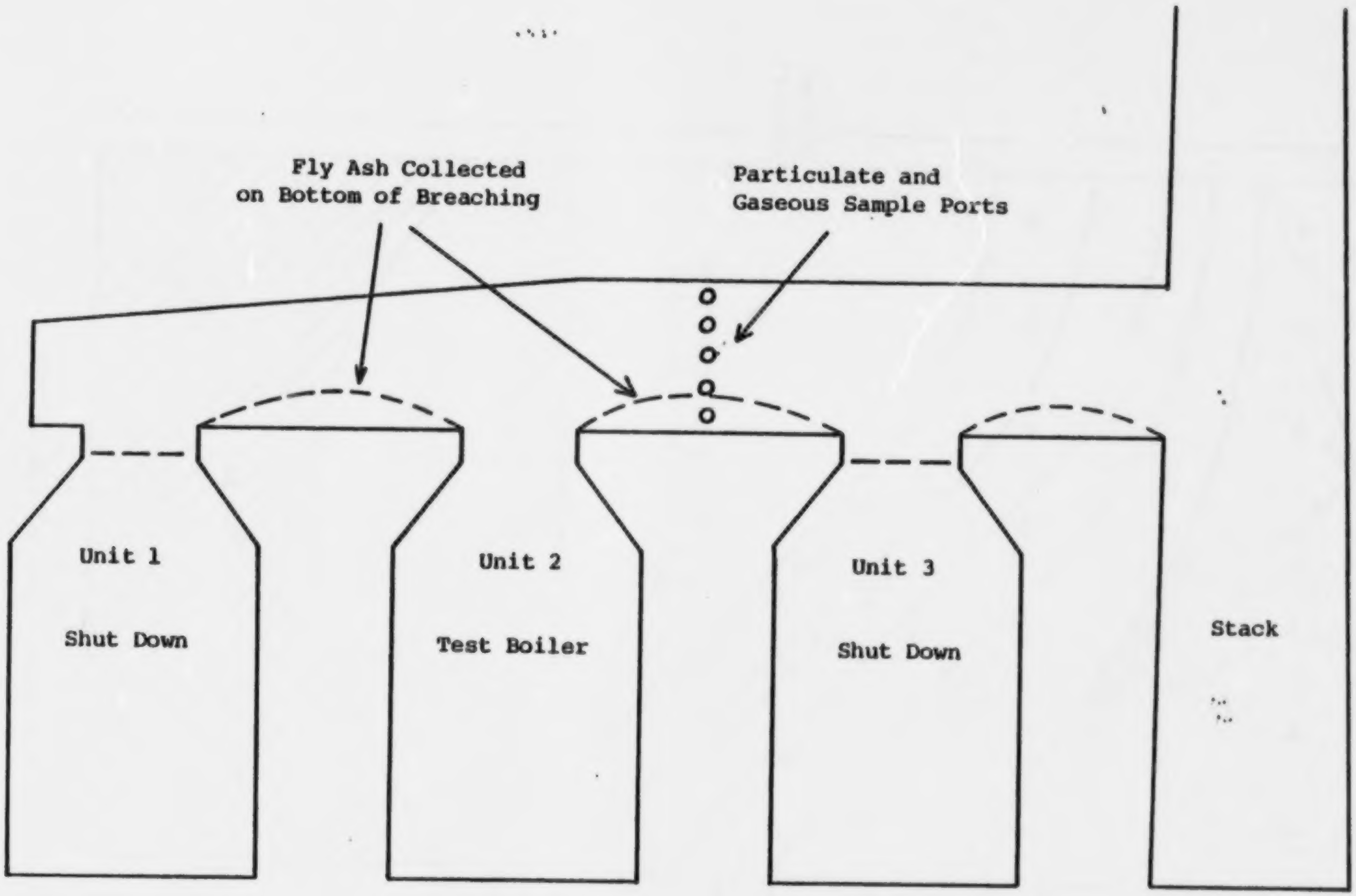
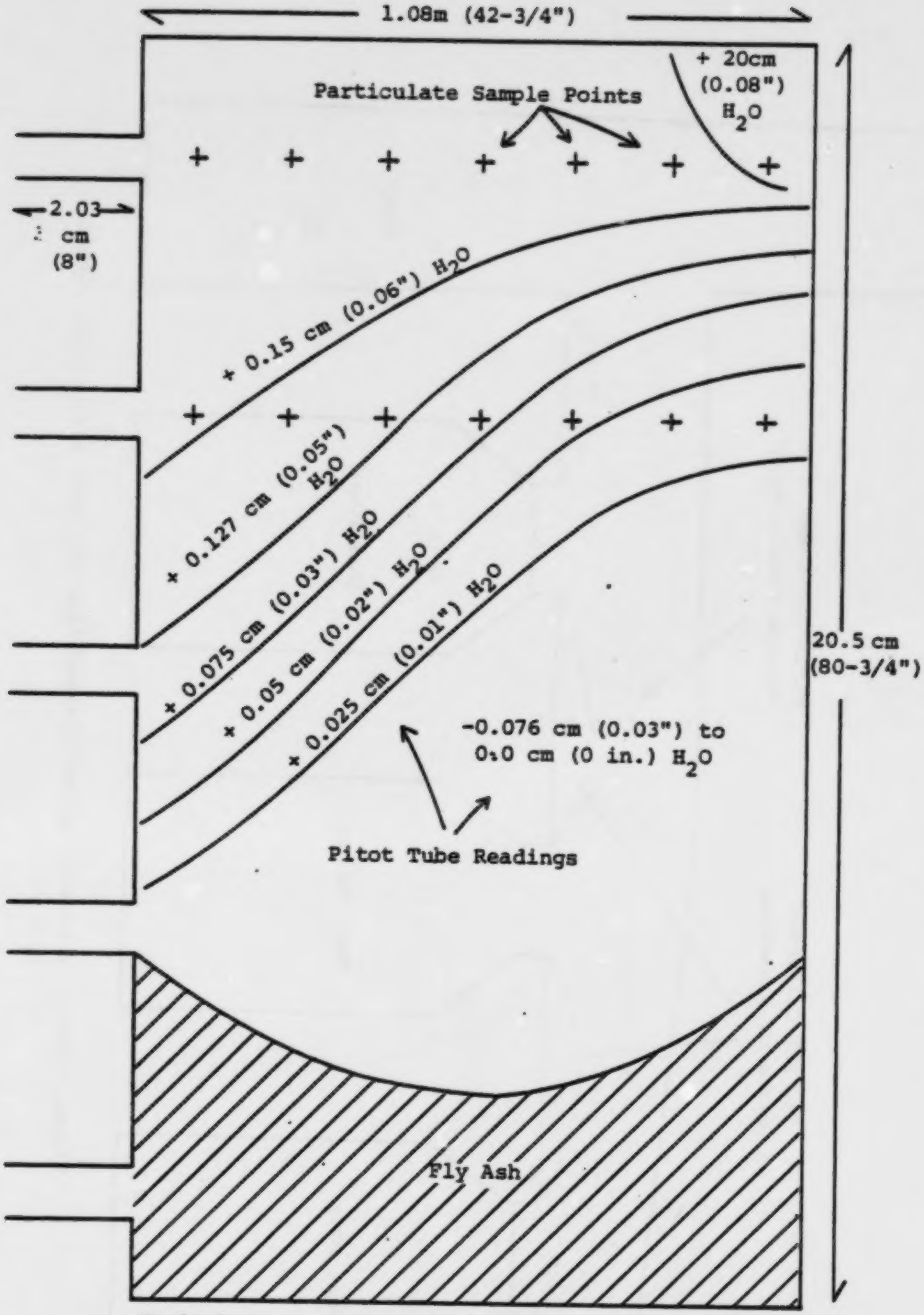

Fly Ash Collected
on Bottom of Breaching
Particulate and
Gaseous Sample Ports
Unit 1
Shut Down
Unit 2
Test Boiler
Unit 3
Shut Down
Stack

Figure 5.9-1. Schematic of boilers and flue gas duct system, St. John's Unit 2.


1.08m (42-3/4")
+ 20cm (0.08") H_2O
Particulate Sample Points
2.03 cm (8")
+ 0.15 cm (0.06") H_2O
+ 0.127 cm (0.05") H_2O
+ 0.075 cm (0.03") H_2O
+ 0.05 cm (0.02") H_2O
+ 0.025 cm (0.01") H_2O
-0.076 cm (0.03") to 0.0 cm (0 in.) H_2O
Pitot Tube Readings
20.5 cm (80-3/4")
Fly Ash

Scale 1 cm = 10 cm (1" = 10")
Effective Area = 1.76 m^2 (18.93 ft^2)

Figure 5.9-2. Sample area geometry, St. John's Abbey Unit 2.

5.9.4 Control Room Observations

During each test, complete records were kept of boiler temperatures and pressures, stoker and boiler controls, coal, feedwater and steam flow rates, etc. Additionally, notes were kept on flame observations and general operating problems. In comparing the two fuels, the following differences were observed:

Last-pass temperature, or temperature of the flue gas exiting the boiler, averaged 602°K (623°F) for the eastern coal burning compared to 579°K (573°F) for the western coal burning. This 28°K (50°F) difference represents a significant heat loss for the eastern coal. Temperatures at the particulate sampling point in the breeching were 507°K (452°F) versus 696°K (425°F) respectively for eastern versus western coal firing; less difference, but still in the same direction.

When ashes from western coal fires are dumped and coal feed is restored to the bare grate, air must be added immediately to initiate burning. When eastern coal is burned, air is not added until the fire has started and is well under way, otherwise it will blow out the fire.

The eastern coal flame appeared more orange and luminous than the western coal flame.

Clinker formation on the grate was not a problem with either coal as long as adequate grate air was supplied. However, low excess air tests revealed that the western coal forms clinkers more readily than the eastern coal. This observation is supported by the western coal's lower ash fusion temperature as indicated in Table 5.9-1.

St. John's Unit #2 operating personnel disliked this particular eastern coal because it was dry and dusty. They ordinarily prefer eastern coals to western coals because of the reduced fuel handling involved in firing higher heating value coals.

This boiler is not load-limited when firing western coal according to the chief engineer. However, the western coal seems to react slower to load demand changes.

Both coals can be burned in this boiler without problems. In fact, neither boiler nor stoker controls changed noticeably from one coal to the next. Smoke was not a problem.

During test number 18, an eastern coal test, the effect of overfire air (OFA) on gaseous emissions was investigated. Varying overfire air between its maximum and minimum settings was found to have no observable effect on either smoke or carbon monoxide at medium loads. However, raising overfire air increased nitric oxide emissions by 14 ppm or 4.6%. A similar experiment during western coal test number 9 showed no effect on smoke, carbon monoxide or hydrocarbons. Again, nitric oxide emissions increased by about 10 ppm. A particulate test at maximum OFA (test #9) could not be directly compared with one at minimum OFA (test #2) because of the inability to duplicate load and excess O_2 conditions. However, no significant change is apparent from the data.

5.9.5 Gaseous Emissions

A. Discussion of Gaseous Testing--

Compared to the baseline eastern coal, the western coal showed lower particulates by a factor of 0.5, increased sulfur dioxide emissions by a factor of 1.3, much higher sulfur trioxide emissions by a factor of 6.9, reduced nitric oxide emissions by a factor of 0.7, nearly equivalent carbon monoxide emissions, and increased hydrocarbon emissions by a factor of 1.5. Each of these emissions is discussed in more detail in the following subsections. The gaseous data is summarized in Table 5.9-2.

Unit #2 was the only boiler operating at St. John's during the summer, and the facility has no tie-in with outside power sources. For these reasons, test loads were restricted to internal demand. A six point test matrix was selected consisting of normal, high, and low excess O_2 tests

TABLE 5.9-2. GASEOUS EMISSION SUMMARY, ST. JOHN'S UNIT 2

	Test No.	Load kg/s	Load (10^3 lb/hr)	O_2 %	CO_2 %	O_2+CO_2 %	CO ppm at 3% O_2	HC ppm at 3% O_2	Nitric Oxide (NO)			SO_x/SO_3			Particulates	
									ppm at 3% O_2	lb/MBtu	ng/J	ppm at 3% O_2	lb/MBtu	ng/J	lb/MBtu	ng/J
WESTERN COAL	1	1.1	(8.82)	13.96	5.93	19.89	48	36	238	0.208	89	—	—	—	—	—
	2	1.1	(8.48)	13.75	5.57	19.32	50	—	226	0.197	85	489/20	0.911/ 0.037	392/ 16	0.446	192
	3	0.7	(5.60)	16.33	3.98	20.31	961	—	216	0.188	81	635/52	1.183/ 0.097	508/ 42	0.846	364
	4	0.7	(5.85)	16.48	3.65	20.13	1032	348	232	0.202	87	614/45	1.143/ 0.084	492/ 36	1.114	479
	5	0.7	(5.72)	15.16	4.89	20.05	95	277	199	0.174	75	759/44	1.414/ 0.082	608/ 35	0.225	97
	6	0.7	(5.86)	17.00	3.51	20.51	1645	377	244	0.213	94	636/55	1.184/ 0.102	509/ 44	1.887	811
	7	1.1	(8.69)	15.21	5.45	20.66	543	233	281	0.245	105	600/39	1.117/ 0.073	480/ 31	0.858	369
	8	1.1	(8.75)	13.38	6.53	19.91	80	125	250	0.218	94	592/26	1.103/ 0.048	474/ 21	0.817	351
	9	1.2	(9.16)	13.50	6.35	19.85	78	132	245	0.214	92	—	—	—	0.557	240
	AVG	0.9	(7.44)	14.97	5.10	20.07	504	218	237	0.207	89	618/40	1.151/ 0.075	495/ 32	0.844	363
EASTERN COAL	10	1.2	(9.64)	13.22	6.20	19.72	41	—	—	—	—	—	—	—	—	—
	11	1.1	(8.57)	14.20	5.72	19.92	157	—	—	—	—	464/19	0.852/ 0.017	366/ 7	1.435	617
	12	0.8	(6.08)	15.48	4.20	19.68	778	54	357	0.307	132	448/3	0.823/ 0.006	354/ 2	2.407	1035
	13	0.7	(5.90)	16.30	3.75	20.05	1446	367	—	—	—	388/1	0.713/ 0.002	306/ 1	3.395	1460
	14	0.7	(5.87)	15.48	4.55	20.03	418	143	305	0.262	113	523/14	0.961/ 0.026	413/ 11	1.075	462
	15	1.1	(8.36)	15.58	5.08	20.66	490	93	413	0.355	153	471/8	0.865/ 0.015	372/ 6	1.827	785
	16	1.0	(7.98)	13.40	6.10	19.50	116	71	264	0.227	98	375/0	0.689/ 0.000	296/ 0	0.530	228
	17	0.9	(7.12)	14.60	5.50	20.10	170	—	325	0.280	120	—	—	—	2.710	1165
	18	1.0	(7.75)	14.34	4.68	19.02	226	130	344	0.296	127	—	—	—	1.287	553
	AVG	0.9	(7.47)	14.73	5.12	19.85	427	143	335	0.288	124	445/6	0.817/ 0.011	351/ 5	1.833	788

at both a low and a medium load. The low load tests were run at night between the hours of 11:30 pm and 4:30 am. During this period the load remained relatively stable at about 0.7 kg/s (5.8×10^3 lb/hr) steam, or 43% of maximum continuous load. Medium load tests were conducted during the day and averaged about 1.1 kg/s (8.5×10^3 lb/hr) steam, or 63% of maximum continuous load. During the day tests, the load varied between about 0.9 kg/s and 1.3 kg/s (7×10^3 lb/hr and 10×10^3 lb/hr) steam which contributed to scatter in the data. Peak load tests could not be obtained during the summer.

Non-steady boiler loads were not the only difficulty at this test site. Small units seldom have the excess O_2 monitors or sophisticated control equipment to maintain excess O_2 at a given level. Instead, much depends on operator judgment by visual reference to the fire. Thus, test conditions (excess O_2 and boiler load) were subject to variation.

Figures 5.9-3 and 5.9-4 show the excess O_2 and boiler load conditions under which the various tests were conducted. The numbers on these and all following graphs refer to test numbers and can be used for cross reference.

1. Particulate Emissions--Particulate emissions from the western coal firing were less than half those of the eastern coal firing under the same conditions. These emissions showed a strong dependence on excess air. To illustrate, the particulate emissions are plotted against boiler load in Figure 5.9-5 and against excess O_2 in Figure 5.9-6. Some care must be taken in interpreting the data of Figure 5.9-6 due to the fact that the nominal low, normal, and high O_2 levels change as the load changes so the curves do not show decreasing particulates at constant O_2 for load increases.

Of special significance are the shapes of the curves in Figure 5.9-6. The western coal behaved as might be expected, increasing at an accelerating rate as the excess O_2 increased, and increasing with load at constant excess O_2. The eastern coal, on the other hand, increased at a decelerating rate as the excess O_2 increased and the particulate emissions were greater at lower load.

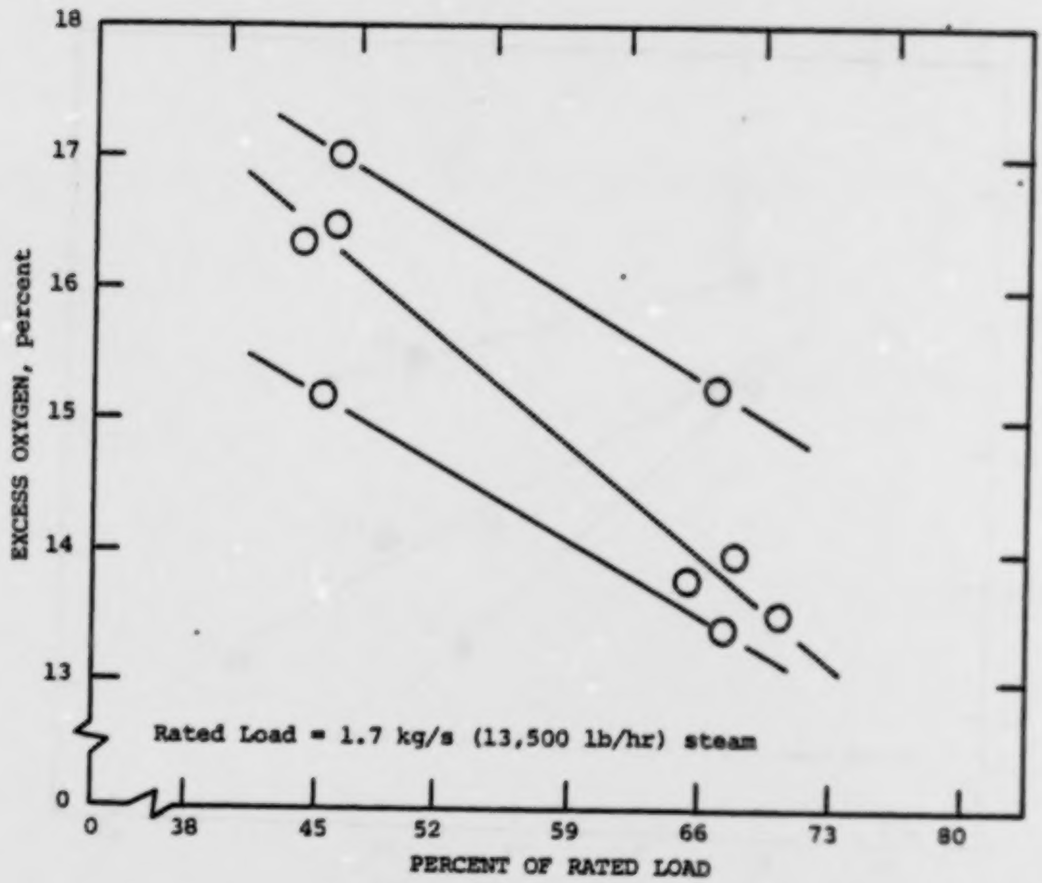


Figure 5.9-3. Western coal test conditions, St. John's Unit 2.

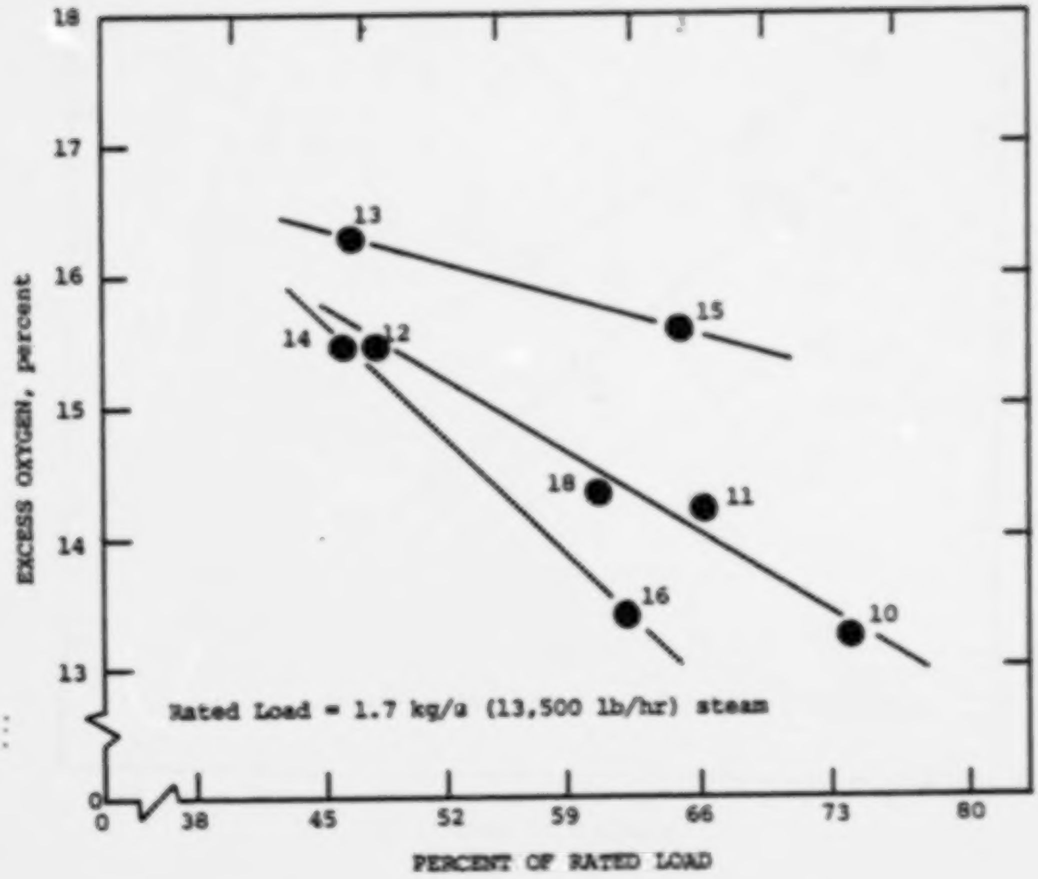


Figure 5.9-4. Eastern coal test conditions, St. John's Unit 2.

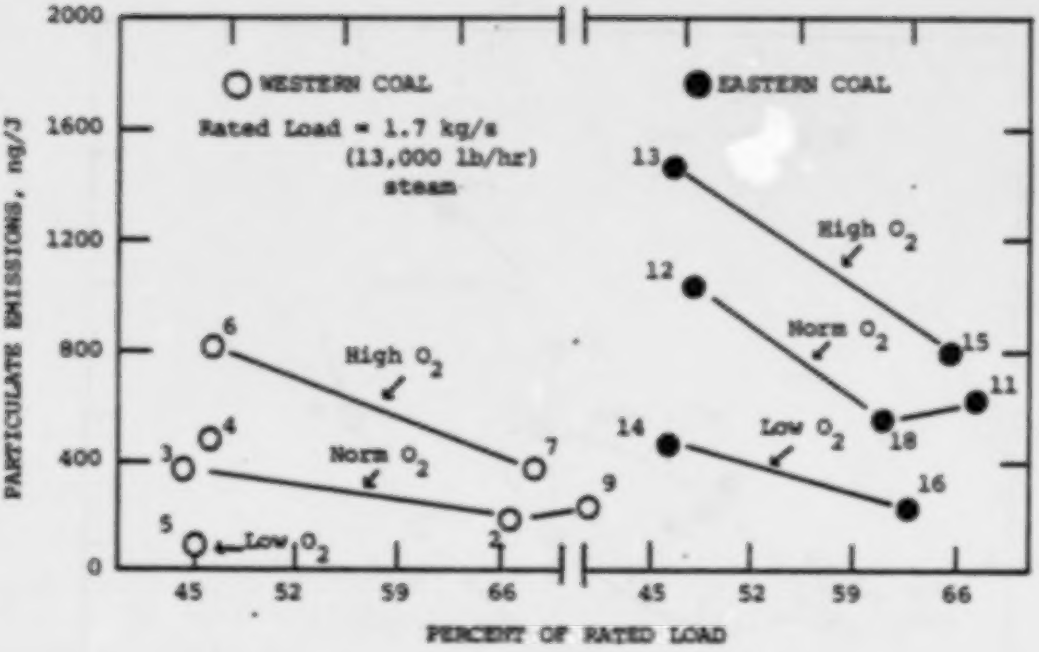


Figure 5.9-5. Particulates vs. load, St. John's Unit 2.

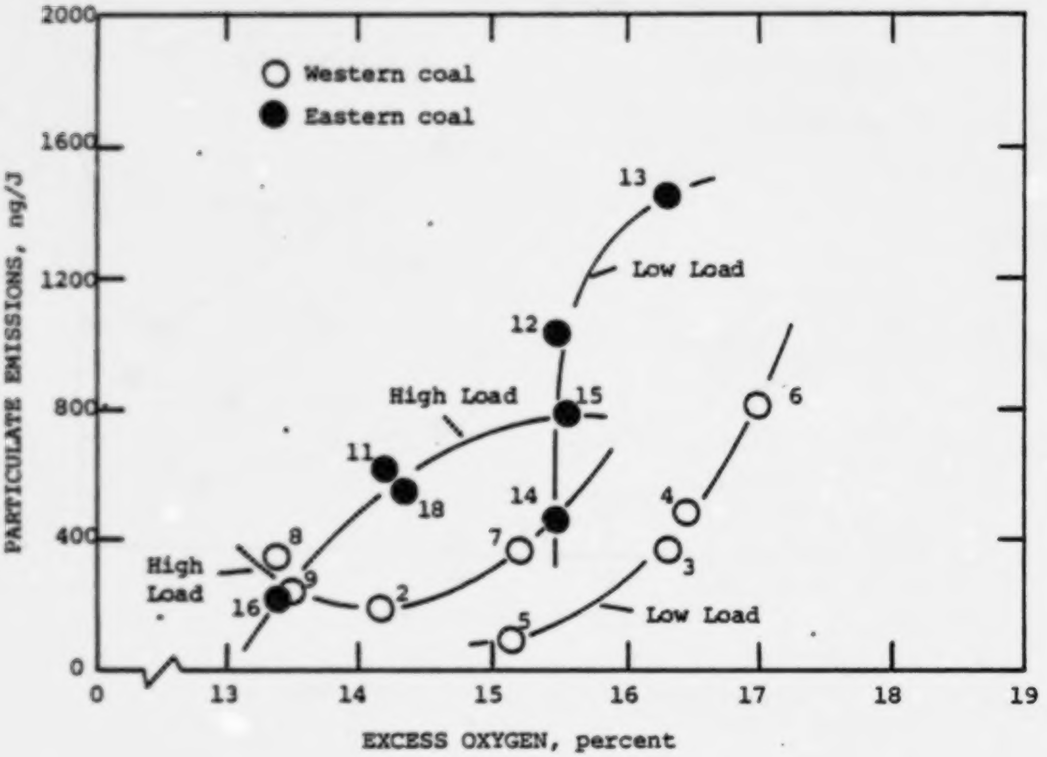


Figure 5.9-6. Particulate emissions vs. excess O_2, St. John's Unit 2.

B. Sulfur Oxides Emissions--

Total oxides of sulfur emissions were lower with eastern coal firing by an average of 40%. This unusual occurrence is a direct result of the low fuel sulfur in this eastern coal, as a comparison of tests 8 (western coal) and 11 (eastern coal) demonstrates. These data are given in Table 5.9-3.

TABLE 5.9-3. SULFUR BALANCE COMPARISON FOR TWO FUELS, ST. JOHN'S UNIT 2

Test No.	HHV of Fuel MJ/kg	HHV of Fuel lb/MBtu	Sulfur in Fuel %	Sulfur in Fuel lb/MBtu as SO_2	SO_2 Emissions ng/J	SO_2 Emissions lb/MBtu	% Emission of Fuel S
8(western)	24.4	10515	0.61	1.160	474	1.103	95%
11(eastern)	31.7	13640	0.58	0.884	366	0.852	96%
16(eastern)	30.5	13123	0.58	0.884	296	0.689	78%(clinker formation)

It is evident that the emissions are directly related to the sulfur input, and that sulfur retention in the ash is low. In the case of test number 16, the computed sulfur retention was 22%. This high sulfur retention could be related to the heavy clinker formation during this test. These are the only three tests for which sulfur analyses were made.

Total oxides of sulfur are plotted against boiler load in Figure 5.9-7. The apparent drop in sulfur emissions at medium load for the western coal may be related to variations in fuel sulfur or just scatter in the data. No variation with excess O_2 was observed. Average SO_x emissions were 495 ng/J (1.15 lb/MBtu) for the western coal and 351 ng/J (0.82 lb/MBtu) for the eastern coal.

Sulfur trioxide emissions are plotted against boiler load in Figure 5.9-8. For the eastern coal firing, average SO_3 emissions were 4.6 ng/J (0.011 lb/MBtu). This is 1.3% of the total oxides of sulfur. For the western coal firing, the SO_3 emissions were 32.1 ng/J (0.075 lb/MBtu). This represents a factor of 6.8 in SO_3 emissions over the eastern coal and accounts for 6.5% of the total western coal oxides of sulfur emission.

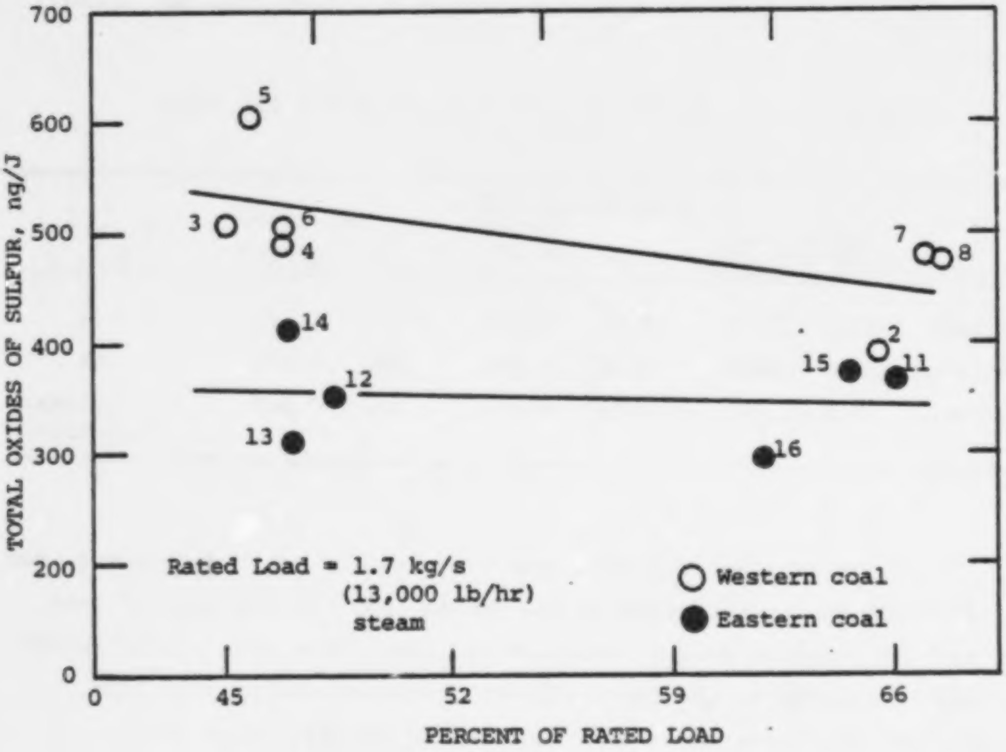


Figure 5.9-7. Total oxides of sulfur vs. boiler load, St. John's Unit 2.

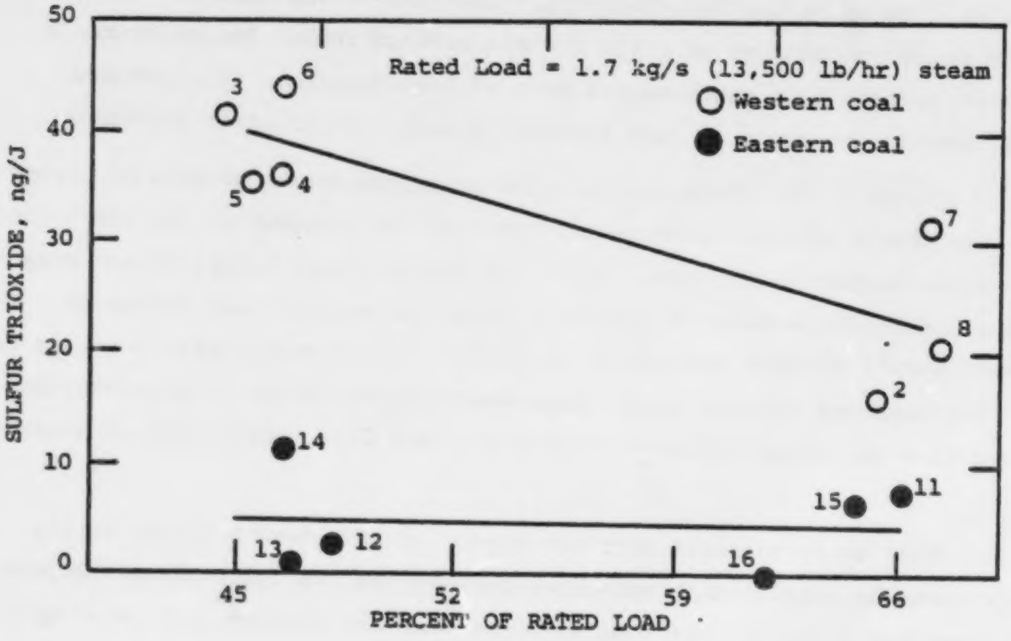


Figure 5.9-8. Sulfur trioxide vs. boiler load, St. John's Unit 2.

1. Nitric Oxide Emissions--Compared to the eastern coal, western coal firing produced an average 28% lower nitric oxide emissions. This reduction is probably the result of the higher moisture content of the western coal. Based on the fuel analysis, Table 5.9-1, the western coal had 15.77% moisture compared to 5.18% for the eastern coal. The moisture in the fuel absorbs heat equal to its heat of vaporization. This reduces flame temperature which in turn reduces thermal nitric oxide formation.

Figure 5.9-9 shows nitric oxide emissions as a function of excess O_2. The effect of load (furnace temperature) is apparent in the separation of the two western coal plots. Also, the eastern coal emissions are seen to have a greater dependence on excess O_2 than the western coal emissions. The western coal's reduced dependence on excess O_2 is probably also a result of the fuel moisture wherein lower flame temperatures result in reduced rates of reaction for nitric oxide formation and thus less sensitivity to excess O_2.

Fuel bound nitrogen does not appear to have been a factor in the differences in nitric oxide emissions between the two fuels since the western coal contains slightly more fuel nitrogen than the eastern coal on a ng/J basis.

2. Carbon Monoxide and Hydrocarbon Emissions--Compared with the baseline coal, the western coal's carbon monoxide (CO) emissions were slightly reduced under most test conditions while the hydrocarbon (HC) emissions were 52% greater on the average. Both of these emission rates are closely related indicators of combustion efficiency.

The CO and HC data are plotted against excess O_2 in Figures 5.9-10, 5.9-11, 5.9-12, and 5.9-13. As with particulates, the western coal data behaved well while the eastern coal behaved in an unorthodox manner. Both emissions increase with excess O_2 at constant load and this can be explained as a cooling or quenching of the flame by the excess air before combustion is complete.

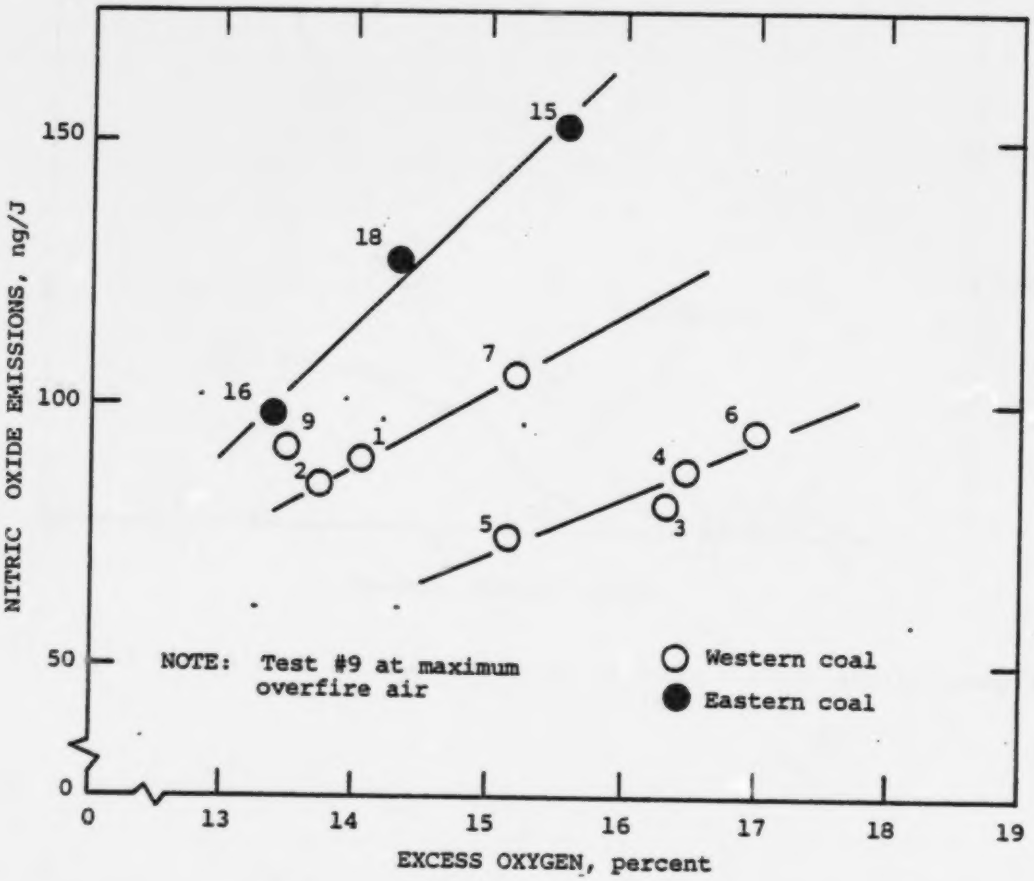


Figure 5.9-9. Nitric oxide vs. excess O_2, St. John's Unit 2.

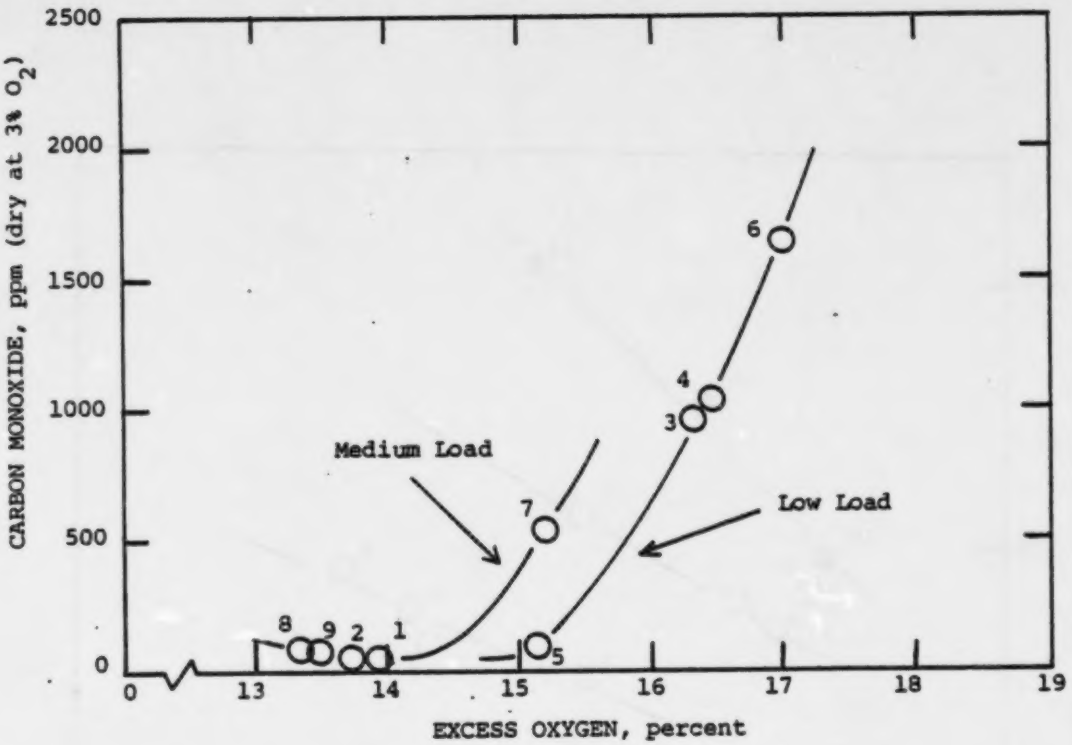


Figure 5.9-10. Carbon monoxide vs. excess O_2, St. John's Unit 2, western coal.

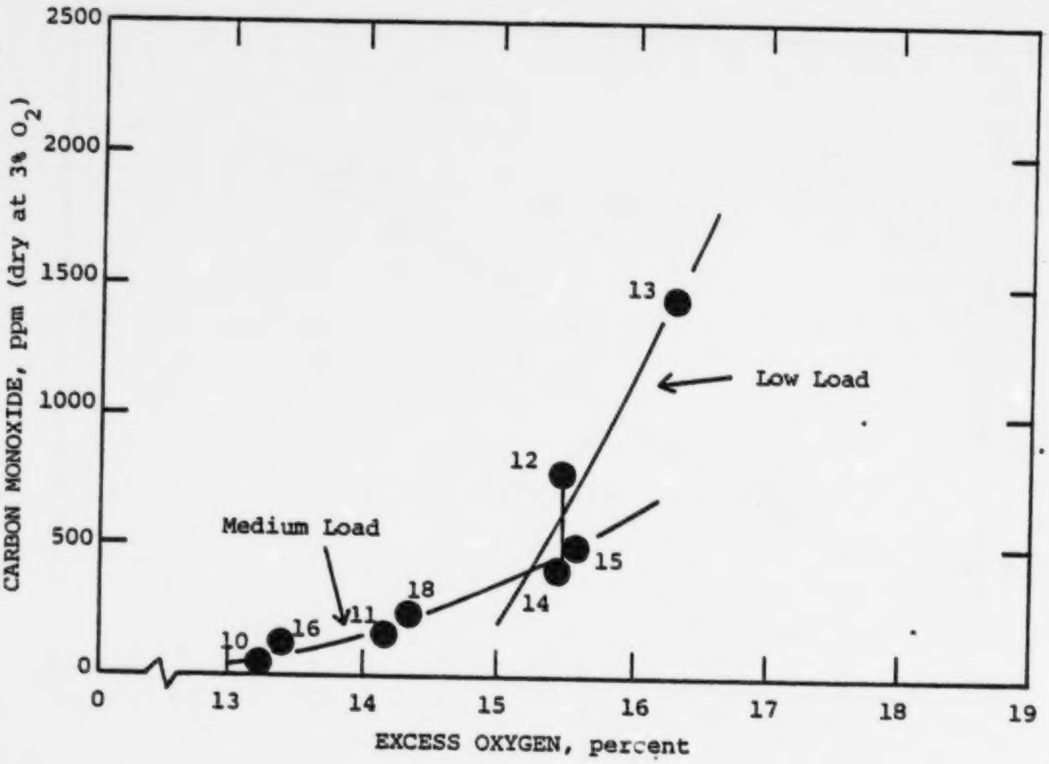


Figure 5.9-11. Carbon monoxide vs. excess O_2, St. John's Unit 2, eastern coal.

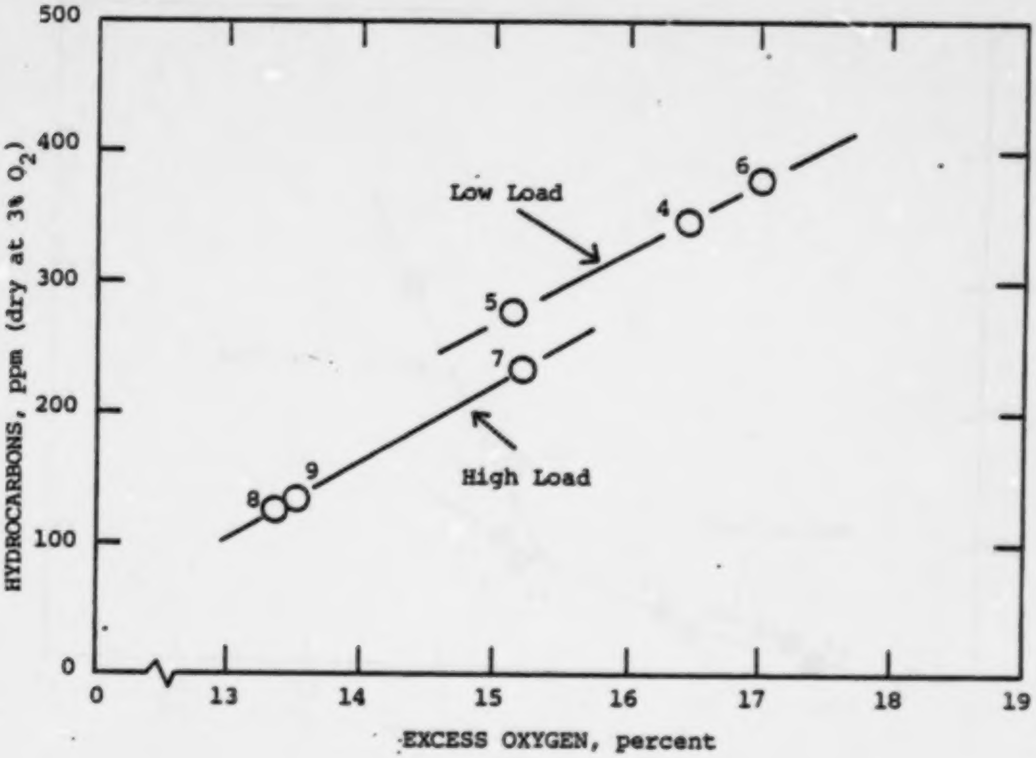


Figure 5.9-12. Hydrocarbons vs. excess O_2, St. John's Unit 2, western coal.

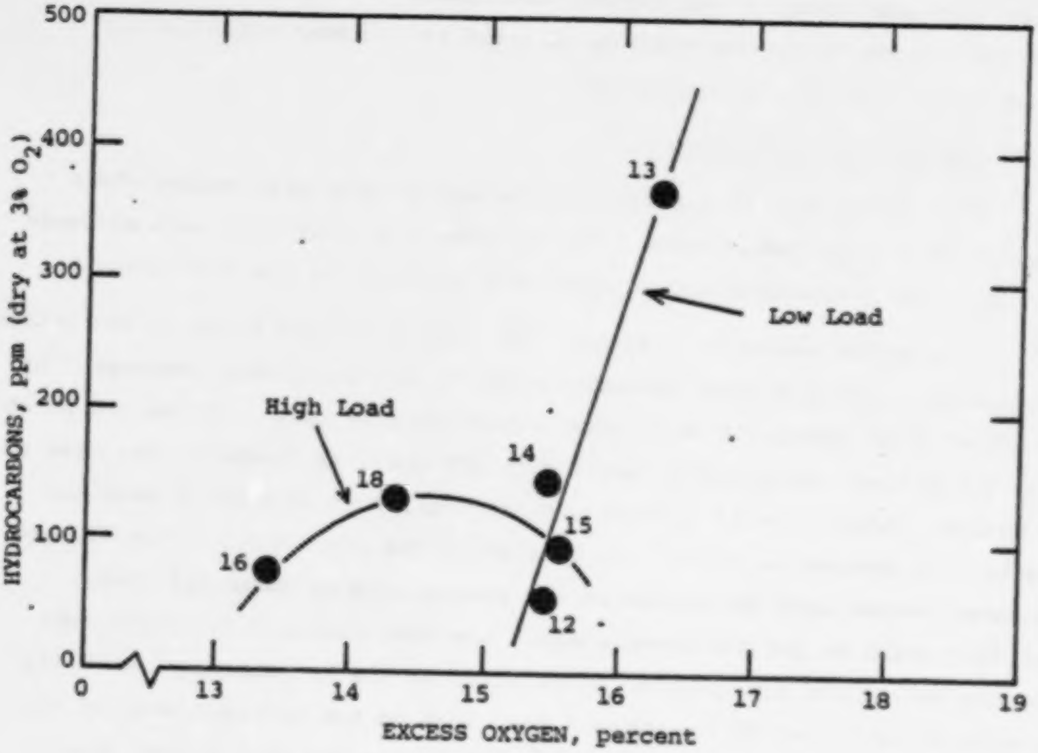


Figure 5.9-13. Hydrocarbons vs. excess O_2, St. John's Unit 2, eastern coal.

The CO and HC emissions generally increase with load in the region of the boiler's load range tested. However, excess O_2 requirements decrease as load increases. The net result is a slight decrease in these emissions as load increases under actual firing conditions. Based on previous test experience, these emissions would be expected to increase again as the maximum boiler capacity is approached.

5.9.6 Ash Balance Measurements

St. John's Unit #2 was the only boiler in this test series where accurate ash balance measurement could be made. We felt that such measurements would be informative and so they were included in the test plan.

The system worked as follows. The left and right sides of the boiler had separate dumping grates, spreader stokers, and air plenum chambers. At the end of each operator's shift when a considerable amount of ash had built up on the grates, the operator would shut off the coal feeder to one side of the boiler. After 5 to 10 minutes without coal, that side would burn out leaving only smoldering ashes. At this point the air would be shut off and the ashes dumped into the bottom of the plenum chamber under the grate. Coal feed would be resumed immediately. The coal feeder would throw coal onto the bare grate and ignition would start at the hot sides and work its way toward the center of the grate. Coal feed to the opposite side of the boiler would be simultaneously increased to handle the entire load demand until the fire on the freshly dumped side had built up sufficiently. About 15 to 20 minutes after the first side had been dumped, the fire would be built up sufficiently to repeat the process on the second side.

Normally, a sprinkler system in the plenum chamber would be used to cool the ashes and keep the dust down before removal. For the purposes of these test measurements, however, they were left dry.

The ashes were shoveled into a wheelbarrow from a door in the air plenum chamber while the air was still shut off. The wheelbarrow was weighed, tare weighed, and the net ash weight recorded. One heaping wheelbarrow full from each side was all that was required. Ash formation rates were thus determined on a mass per unit time basis.

Fuel feed rates were simultaneously determined on a Kg/hr and lb/hr basis. The feeder hopper was topped off at the start and finish of each test and the times recorded. The coal added to the hopper during the test was weighed to the nearest ten pounds.

Finally, particulate emissions were computed on a Kg/hr and lb/hr basis. This data is tabulated in Table 5.9-4 and graphically illustrated in Figures 5.9-14 and 5.9-15. A discussion of the results follows.

The western coal's ash balance was very good. During test number 7 the fuel flow rate was apparently erroneously measured since it is unusually high for the boiler load. This would account for the high "ash in fuel" flow rate.

For a given load, the fly ash fraction of the total ash increases sharply with excess air. The only deviation from this trend is test number 8 where clinker formation may have resulted in higher local air flows through portions of the grate, thus increasing ash carry over.

The "ash in fuel" flow rate for all the western coal measurements is based on a coal analysis from test number 8. Thus, test number 8 should be the most accurate ash balance test. An analysis of the bottom ash for test number 8 shows 11.29% combustibles and ignition of fly ash samples for test numbers 2 through 9 gave an average weight loss of 8%. Therefore, about [illegible]0% of the carbon containing ash was accounted for.

"Ash in fuel" calculations for the eastern coal were made from a coal analysis of the fuel used in test number 16. The dry combustibles in the grate ash from test number 16 were found to be 20.72%. An average of eight fly ash samples showed a loss on ignition of 39.4%. Very close to a 100% ash balance for the seven tests was obtained.

TABLE 5.9-4. ASH BALANCE DATA, ST. JOHN'S UNIT 2

	Test No.	Load kg/s	Load (10^3 lb/hr) Steam	Excess O_2 %	(a) Ash in Fuel Kg/hr	(a) Ash in Fuel (lb/hr)	(b) Grate Ash Kg/hr	(b) Grate Ash (lb/hr)	(b) Grate Ash %	(c) Fly Ash Kg/hr	(c) Fly Ash (lb/hr)	(c) Fly Ash %	Difference (b)+(c)-(a) %
Western Coal	3	0.7	5.60	16.33	19.3	42.53	15.9	33.96	79.8	3.34	7.36	17.3	- 2.9
	4	0.7	5.85	16.48	20.4	45.08	16.1	35.44	78.6	4.66	10.27	22.88	+ 1.4
	5	0.7	5.72	15.16	18.4	40.56	17.8	39.11	96.4	8.53	1.88	4.6	+ 1.0
	6	0.7	5.86	17.00	22.2	48.98	16.0	35.24	71.9	8.58	18.91	38.6	+10.5
	7	1.1	8.69	15.21	31.8	70.11	19.6	43.28	61.7	5.59	12.31	17.6	-20.7
	8	1.1	8.75	13.38	27.2	59.98	23.6	51.91	86.5	4.78	10.53	17.6	+ 4.1
	9	1.2	9.16	13.50	28.7	63.27	25.5	56.23	88.9	3.27	7.21	11.4	+ 0.3
Eastern Coal	11	1.1	8.57	14.20	18.1	39.89	16.5	36.27	90.9	6.45	14.20	35.6	+26.5
	12	0.8	6.08	15.48	15.4	33.94	14.8	32.61	96.1	9.20	20.27	59.7	+55.8
	13	0.7	5.90	16.30	16.5	36.30	12.6	27.76	81.8	13.9	30.57	84.2	+66.0
	14	0.7	5.87	15.48	13.9	30.09	14.0	30.86	100.6	3.71	8.18	26.7	+27.3
	15	1.1	8.36	15.58	18.4	40.52	16.7	36.84	90.9	8.33	18.36	45.3	+36.2
	16	1.6	7.98	13.40	18.4	40.58	17.4	38.23	94.2	2.42	5.34	13.1	+ 7.3
	18	1.0	7.75	14.34	18.1	40.63	18.6	41.02	101.0	5.89	12.97	31.9	+32.9

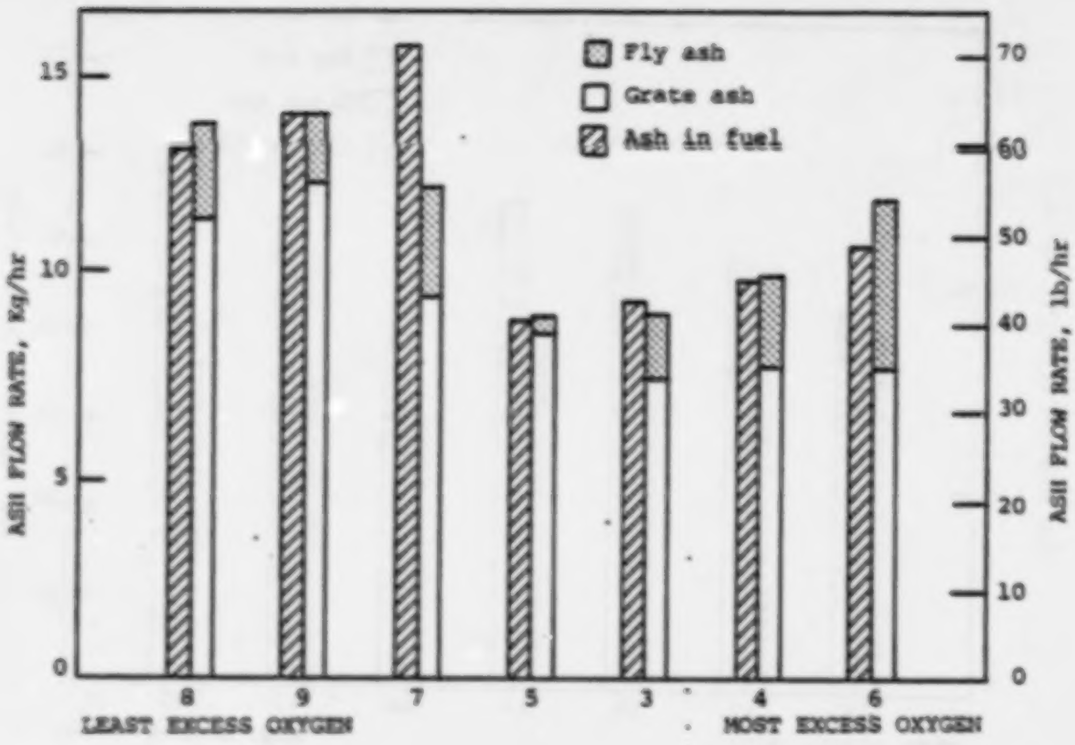


Figure 5.9-14. Western coal ash balance (disregarding carbon analyses), test numbers arranged in order of excess O_2, St. John's Unit 2.

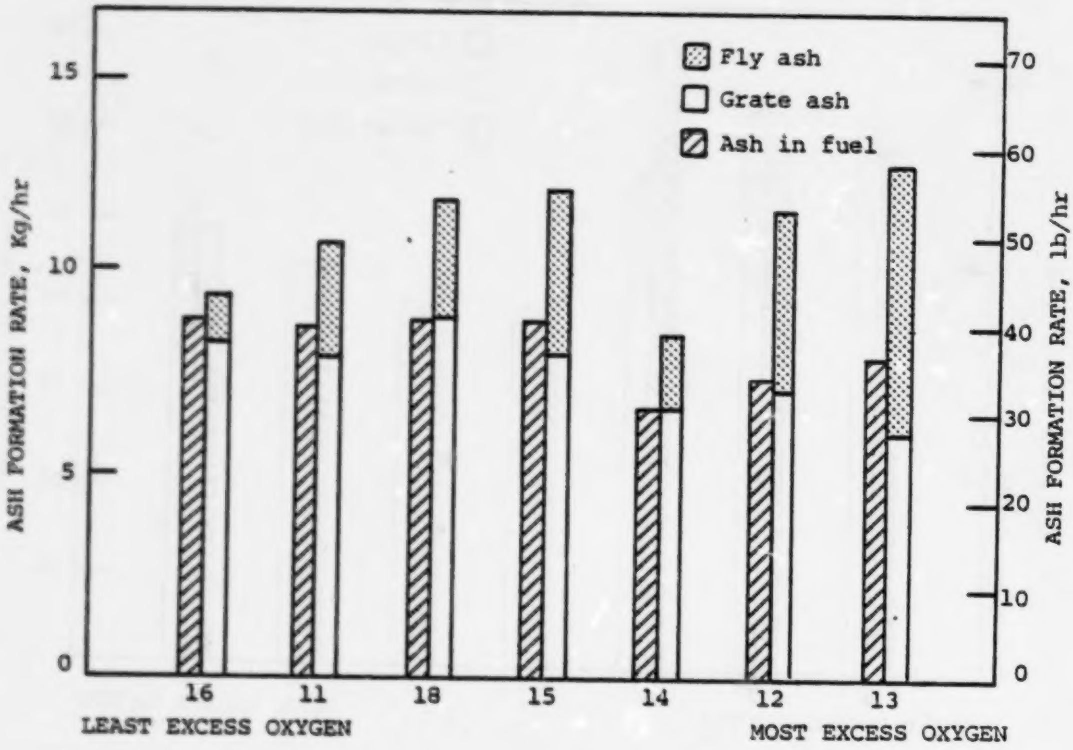


Figure 5.9-15. Eastern coal ash balance (disregarding carbon analyses), test numbers arranged in order of excess O_2, St. John's Unit 2.

5.9.7 Concluding Remarks

1. A western coal can be burned in small dumping grate spreader stokers of this type without operating problems. No boiler modifications are required.

2. Particulate and nitric oxide emissions were significantly reduced by burning the western coal, while carbon monoxide emissions were unaffected.

3. Total oxide of sulfur emissions were in direct proportion to the sulfur content of the fuel based on a higher heating value. Sulfur retention in the boiler was not a significant factor.

4. Units of this type would benefit from the installation of continuous excess O_2 monitors because all emissions and clinker formations are highly sensitive to excess O_2.

5.10 FREMONT DEPARTMENT OF UTILITIES, FREMONT, NEBRASKA

Lon D. Wright Memorial Power Plant in Fremont, Nebraska, was the last site in our test series. The unit tested was a small 20.2 kg/s (160,000 lb/hr) steam face-fired pulverized coal burning unit with a dry bottom, and a mechanical dust collector.

The unit was originally designed for a subbituminous Kansas coal. At the time our testing started, the unit was burning Hanna Wyoming coal as its primary fuel and was considering a switch to one of several Colorado coals for reasons of emissions and economics. At the completion of our test program the facility continued to burn the Colorado coal we had tested. This allowed us to assess the long term operational problems of both coals.

Proximate and ultimate analysis of the two fuels is given in Table 5.10-1.

5.10.1 Boiler Description

The boiler tested was Unit 6 at the Lon D. Wright Memorial Power Plant in Fremont, Nebraska. It is a 20.2 kg/s (160,000 lb/hr) steam flow, pulverized coal burning unit of the Stirling type built by Babcock and Wilcox Company (B&W) in 1956. The unit is face-fired with four B&W burners arranged in two rows of two. Pulverized coal is supplied to the burners by two B&W ball and race type pulverizers.

Incoming combustion air is preheated by a tubular type air heater to about 589 °K (600 °F). The flue gases pass through a pendant type superheater before beginning the final boiler pass. Superheated steam temperature is controlled at 744 °K (880 °F) by a coil type attemperator. Fly ash is removed by a mechanical dust collector. Ash from the dust collector and from the bottom of the smoke stack is pneumatically conveyed under vacuum to a point where it is mixed with the ash slurry from the bottom ash hopper. The ash slurry is piped to a settling pond and eventually used for land fill. The unit is of the balanced draft type with both induced draft (ID) and forced draft (FD) fans. Furnace draft is maintained at about negative 0.64-0.76 cm (0.25-0.30 inches) of water.

TABLE 5.10-1. COMPARISON OF TEST COALS

FROM TEST #16

Walden Colorado Coal

PROXIMATE ANALYSIS

	As Rec'd	Dry
% Moisture	12.85	xxxxx
% Ash	6.89	7.91
% Volatile	35.24	40.43
% Fixed Carbon	45.02	51.66
	100.00	100.00
MJ/kg	24.9	28.6
Btu/lb	10741	12324
% Sulfur	0.32	0.37

ULTIMATE ANALYSIS

	As Rec'd	Dry
Moisture	12.85	xxxxx
Carbon	61.59	70.67
Hydrogen	4.31	4.95
Nitrogen	0.93	1.07
Chlorine	0.03	0.03
Sulfur	0.32	0.37
Ash	6.89	7.91
Oxygen (dif)	13.08	15.00
	100.00	100.00

FROM TEST #4

Hanna Wyoming Coal

PROXIMATE ANALYSIS

	As Rec'd	Dry
% Moisture	11.97	xxxxx
% Ash	9.19	10.44
% Volatile	33.46	38.01
% Fixed Carbon	45.38	51.55
	100.00	100.00
MJ/kg	25.3	28.7
Btu/lb	10889	12370
% Sulfur	1.48	1.68

ULTIMATE ANALYSIS

	As Rec'd	Dry
Moisture	11.97	xxxxx
Carbon	61.63	70.01
Hydrogen	4.38	4.98
Nitrogen	1.25	1.42
Chlorine	0.03	0.03
Sulfur	1.48	1.68
Ash	9.19	10.44
Oxygen (dif)	10.07	11.44
	100.00	100.00

MINERAL ANALYSIS

	Ignited
Phos. pentoxide, P_2O_5	0.11
Silica, SiO_2	50.08
Ferric oxide, Fe_2O_3	13.74
Alumina, Al_2O_3	19.24
Titania, TiO_2	0.80
Lime, CaO	7.50
Magnesia, MgO	1.92
Sulfur trioxide, SO_3	4.15
Potassium oxide, K_2O	1.61
Sodium oxide, Na_2O	0.48
Undetermined	0.37

T_{250} Poises = 2460 °F
Silica Value = 68.38
Alk. as Na_2O, DCB* = 0.16

The following design data applies to Unit #6:

- Boiler rating - 20.2 kg/s (160,000 lb/hr) steam flow
- Design pressure - 7.0 MPa (1000 psig)
- Design temperature - 761 °K (910 °F) (Superheated)
- Year built - 1956
- Boiler heating surface - 841 m^2 (9,050 sq. ft.)
- Total waterwall heating surface - 333 m^2 (3,584 sq. ft.)
- Superheater heating surface - 441 m^2 (4,748 sq. ft.)
- Air heater heating surface - 3,958 m^2 (42,600 sq. ft.)
- Total furnace volume - 323 m^3 (11,400 cu. ft.)
- Western precipitator multiclone dust collector - 138-8

Predicted Multiclone Efficiency

Particle Size	Expected Efficiency
5-10 microns	53.8%
10-20 microns	96.5%
30-43 microns	98.6%
> 43 microns	99.0%
Overall Average	80.0%

- Stack height - 43.9 m (144 feet)
- B&W ball and race pulverizers - Type E, Size EL-35
- Day-to-day operating conditions:
  - Superheat steam temperature - 744 °K (880 °F)
  - Superheat steam pressure - 6.1 MPa (875 psig)

5.10.2 Sample Locations

Sample ports were available at three different locations along the duct system of the boiler. At each location, the duct was about 4.66 m (15'3") wide and required ports on both sides to provide access to its entire area. The locations of these sample areas and their geometry is shown in Figure 5.10-1.

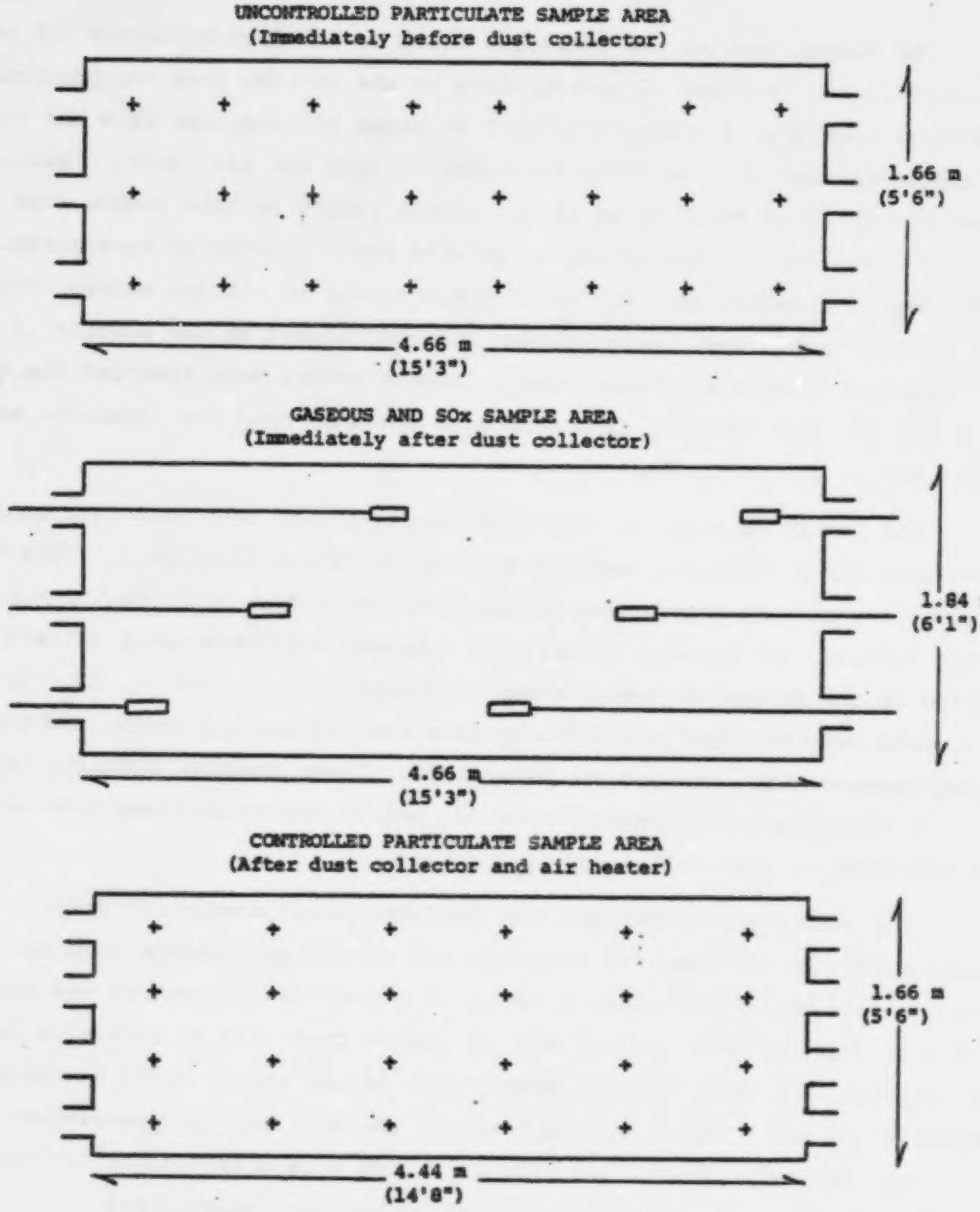

UNCONTROLLED PARTICULATE SAMPLE AREA
(Immediately before dust collector)
1.66 m
(5'6")
4.66 m
(15'3")
GASEOUS AND SOx SAMPLE AREA
(Immediately after dust collector)
1.84 m
(6'1")
4.66 m
(15'3")
CONTROLLED PARTICULATE SAMPLE AREA
(After dust collector and air heater)
1.66 m
(5'6")
4.44 m
(14'8")

Figure 5.10-1. Sample area geometry, Fremont Department of Utilities Unit 6.

The sample area at the immediate inlet to the dust collector was used for particulates. Because of obstructions in the working area, two particulate probes were required, a twelve foot (3.7 m) probe for sampling from the west side and a two foot (0.5 m) probe for sampling from the east side. Combined, the two probes could reach 23 of the 24 sample points in this sample area. The one which could not be reached was in an area where velocities were normally either zero or negative and thus would not normally be sampled anyway. Turbulence in this sample area was a problem and contributed to the scatter in the dust collector inlet particulate data. Gaseous probes were inserted one quarter of the way into the duct from each side and were used for obtaining excess O_2 data during the particulate sampling.

The sample area at the immediate outlet of the dust collector could not be used for particulate sampling because of severe turbulence. This turbulence was due to a 90 degree bend in the flue gas stream as it exited the multiclone. Instead, six gaseous probes with sintered stainless steel filters were inserted in the staggered manner shown in Figure 5.10-1. The O_2, CO_2, CO, NO, and HC data were obtained individually from each of the six probes and the average concentration of each was determined. These averaged readings are the ones used throughout this report. The SO_2 and SO_3 concentrations were obtained from this area by the Shell-Emeryville method.

The sample area after the dust collector and immediately before the induced draft fan was used for obtaining the outlet particulate samples. Again, as at the dust collector inlet, a twenty-four point sample matrix was used. Two probes, one six foot (1.8 m) and one twelve foot (3.7 m) effective lengths, were required. In this way, all twenty-four sample points could be reached. Turbulence was not a major problem here and the data was very consistent. As at the dust collector inlet, two gaseous probes were inserted for the purpose of obtaining excess O_2 values for correcting the particulate data.

5.10.3 Gaseous Data

A. Discussion of Testing--

Some test difficulties did exist at this site. The scheduled start-up of a new unit placed time restrictions on our testing because it would require bringing Unit #6 down. Delays in the shipment of the Walden Colorado test coal and the small size of that shipment placed further time constraints on our test program. Finally, contractual obligations of the plant to a regional electrical power inter-tie made availability of specific unit loads difficult.

To overcome these difficulties and still adequately characterize the boiler emissions as a function of boiler load and excess O_2, a modified test plan was adopted. First, a five point test matrix was selected including low, medium and high load tests followed by one test at higher than normal air and one test at lower than normal air both at the medium load. During each of these tests, the time-consuming inlet and outlet particulates and sulfur oxides tests were run in addition to recording the emissions of O_2, CO_2, CO, NO, and HC monitored in the KVB mobile laboratory.

To more accurately characterize the monitored emissions against excess O_2, a special series of tests were run. In this series, the fuel/air ratio was changed in increments both above and below the normal excess O_2 level. The changes were made at 15 minute intervals. These tests proved to be very beneficial. Boiler loads along with other operating parameters were held constant eliminating the usual probelm of duplicating combustion conditions when these conditions are changed one day at a time. As an added benefit, this approach allowed more accurate determination of the carbon monoxide limit under low excess air conditions.

Figure 5.10-2 shows the conditions under which the various tests were conducted. The numbers on these and all following graphs refer to test numbers and can be used for cross reference.

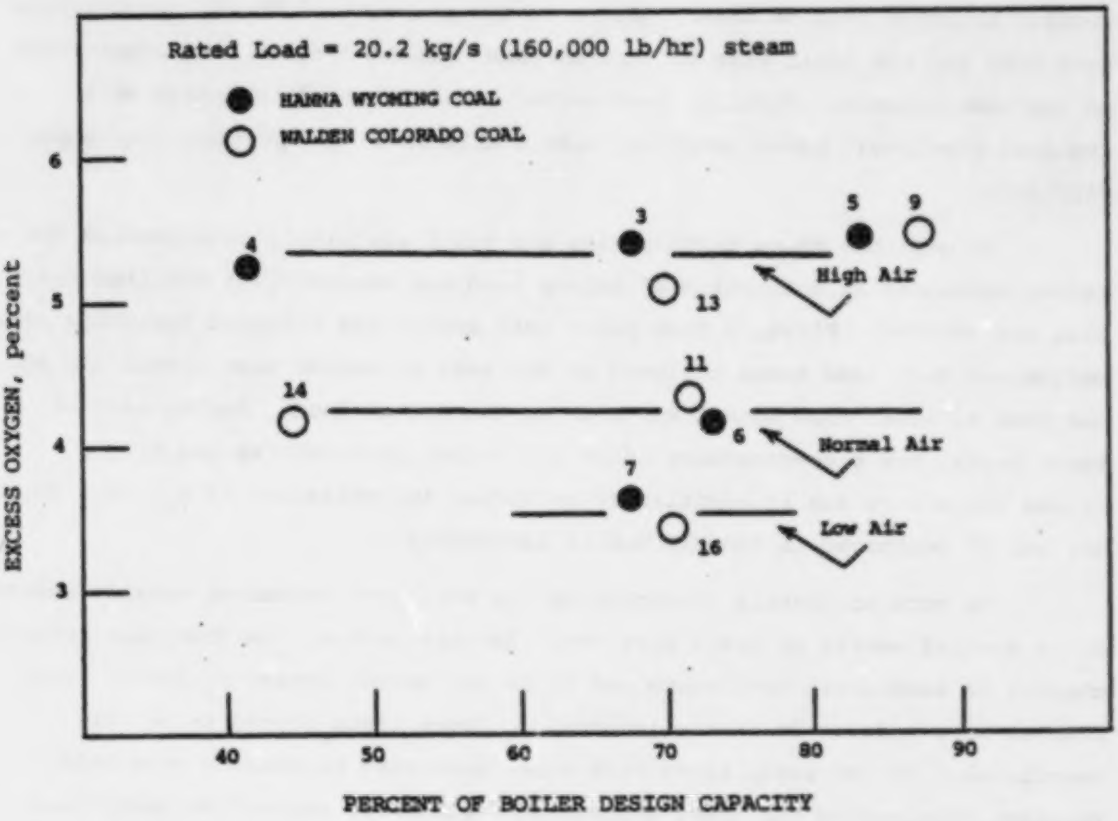


Figure 5.10-2. Excess O_2 vs. boiler load, test parameters, Fremont Department of Utilities Unit 6.

Based on the control room monitor, the normal O_2 for the boiler is 3.8% at all loads. During the Hanna Wyoming coal tests, recalibration of the control room monitor after test number 5 showed that all three baseline tests had been at higher than normal air. Thus, test 6 represents a normal O_2 and test 7 represents a low O_2. The Walden Colorado coal tests followed the desired test matrix more closely, although test 9 was at a higher than normal excess O_2 value. The excess O_2 numbers used in this report were from samples taken after the second stage air heater and the dust collector. Therefore, there was some dilution of the flue gas due to leakage resulting in higher O_2 values than actually existed in the furnace.

Table 5.10-2 presents an emissions data summary for the five comprehensive tests on each fuel. Table 5.10-3 presents the data for those tests in the which fuel/air ratio was varied in increments. The following subsections will address each of the emissions separately and make a direct comparison between the two coals.

B. Particulate Emissions--

The data shows the Walden Colorado coal's particulate emissions were an average 36% less than the Hanna Wyoming coal's emissions as measured at the dust collector outlet. The reason for this reduction appears to be primarily improved collector efficiency in removing the Walden ash, and not the lower ash content of the same fuel. The data is presented in Table 5.10-2 and on Figures 5.10-3, 5.10-4, and 5.10-5 respectively which show particulate emissions before and after the dust collector and collector efficiency as a function of boiler load.

In Figure 5.10-3, inlet particulate loadings for both coals are plotted against boiler load. The difference in ash contents of the two coals, 24% on a HHV basis, is not seen here. Instead, the uncontrolled particulate emissions from both fuels are statistically the same.

Excess air is a factor before the dust collector. Comparing high air tests 3 and 13 against low air tests 7 and 16 shows that a 1% decrease in excess O_2 can decrease emissions by 15% or more. However, this improvement is reduced to around 5% by the normalizing effect of the cyclones as will be discussed in a later paragraph.

TABLE 5.10-2. EMISSION DATA SUMMARY, FREMONT DEPARTMENT OF UTILITIES, UNIT 6

Test No.	Date	Load kg/s (10^3lb/hr)	O_2 percent	CO_2 percent	CO (dry) ppm	HC (wet) ppm	NO		SO_x		SO_3		Fuel Sulfur Emitted percent	Unc. Part ng/J (lb/10^6BTU)	Con. Part ng/J (lb/10^6BTU)	Dust Coll Eff. percent	Comb. in Flyash percent
							(dry) ppm	ng/J (lb/10^6BTU)	(dry) ppm	ng/J (lb/10^6BTU)	(dry) ppm	ng/J (lb/10^6BTU)					
								HANNA WYOMING COAL									
3	7/23/76	13.6 (108.4)	5.39	13.51	11	--	591	225 (0.523)	1215	987 (2.295)	5	4.1 (0.009)	92.8	1133 (2.636)	437 (1.017)	61.4	1.1
4	7/24/76	8.3 (66.0)	5.28	13.45	17	90	460	175 (0.407)	1249	1014 (2.359)	5	4.1 (0.009)	86.9	1141 (2.654)	621 (1.445)	45.6	1.3
5	7/25/76	17.0 (133.5)	5.43	13.31	20	110	659	251 (0.583)	1417	1151 (2.677)	5	4.1 (0.009)	107.3	1508 (3.507)	413 (0.961)	72.6	0.5
6	7/27/76	14.7 (116.0)	4.14	14.88	18	74	--	--	951	772 (1.796)	4	3.2 (0.008)	95.1	--	425 (0.988)	--	0.7
7	7/28/76	13.6 (108.2)	3.61	15.01	17	62	--	--	849	689 (1.604)	3	2.4 (0.006)	86.8	911 (2.119)	431 (1.003)	52.7	0.7
	Average	13.3 (106.6)	4.77	14.03	17	84	570	217 (0.504)	1136	923 (2.146)	4	3.6 (0.008)	93.8	1173 (2.729)	465 (1.083)	58.1	0.86
								WALDEN COLORADO COAL									
9	8/18/76	17.5 (139.9)	5.46	13.70	14	71	488	184 (0.428)	312	251 (0.584)	0.3	0.2 (0.001)	113.4	1566 (3.642)	300 (0.698)	80.8	0.6
11	8/20/76	14.4 (114.9)	4.33	14.40	12	33	390	147 (0.342)	259	208 (0.485)	0.9	0.7 (0.002)	87.5	1176 (2.735)	--	--	0.3
13	8/21/76	14.2 (111.7)	5.06	13.91	10	46	430	165 (0.384)	283	228 (0.530)	26.9	21.7 (0.050)	--	1194 (2.777)	287 (0.667)	76.0	0.5
14	8/22/76	8.9 (71.0)	4.18	14.75	13	161	398	150 (0.349)	228	184 (0.427)	3.8	3.1 (0.007)	68.4	896 (2.085)	330 (0.768)	63.2	1.4
16	8/22/76	14.2 (112.6)	3.41	15.47	61	63	341	129 (0.299)	252	203 (0.472)	0	0	78.7	995 (2.315)	265 (0.617)	73.3	0.9
	Average	13.9 (110.0)	4.49	14.45	22	75	411	155 (0.361)	267	215 (0.499)	6	5.2 (0.012)	87.1	1208 (2.711)	296 (0.688)	73.3	0.74
Walden - Hanna Walden x 100		+3%	-6%	+3%	-23%	-11%		-28%		-77%		+33%	-7%	-0.7%	-36%	+21%	-14%

TABLE 5.10-3. SULFUR BALANCE SUMMARY, FREMONT DEPARTMENT OF UTILITIES, UNIT 6

Test No.	Load kg/s	O_2 percent	SULFUR IN FUEL			SULFUR IN ASH				SULFUR EMISSIONS	
			Fuel Sulfur percent	HHV Fuel MJ/kg (BTU/lb)	As SO_2 ng/J (lb/10^6BTU)	Ash Percent of Fuel	Sulfur Percent of Ash	As SO_2 ng/J (lb/10^6BTU)	Retention percent	SOx ng/J (lb/10^6BTU)	Fuel Sulfur Emitted percent
HANNA WYOMING COAL											
3	13.6	5.39	1.55	29.2 (12533)	1063 (2.473)	9.85	1.30	88 (0.204)	8.3	987 (2.295)	92.8
4	8.5	5.28	1.68	28.8 (12370)	1168 (2.716)	10.44	1.03	75 (0.174)	6.4	1014 (2.359)	86.9
5	17.0	5.43	1.56	29.1 (12509)	1072 (2.494)	9.99	1.10	76 (0.176)	7.0	1151 (2.677)	107.3
6	14.7	4.14	1.16	28.6 (12287)	812 (1.888)	7.76	0.96	52 (0.121)	6.4	772 (1.796)	95.1
7	13.6	3.61	1.14	28.7 (12337)	795 (1.848)	7.95	0.51	28 (0.066)	3.6	690 (1.604)	86.8
Average	13.3	4.77	1.42	28.9 (12407)	984 (2.289)	9.20	0.98	62 (0.145)	6.4	923 (2.146)	93.8
WALDEN COLORADO COAL											
9	17.5	5.46	0.31	28.0 (12047)	221 (0.515)	--	--	--	--	251 (0.584)	113.4
11	14.4	4.33	0.23	27.7 (11912)	238 (0.554)	8.91	0.15	9 (0.022)	4.0	209 (0.485)	87.5
13	14.3	5.06	--	--	--	--	--	--	--	228 (0.530)	--
14	8.5	4.10	0.30	28.3 (12186)	268 (0.624)	7.85	0.23	13 (0.030)	4.7	184 (0.427)	68.4
16	14.2	3.41	0.37	28.7 (12334)	258 (0.600)	7.91	0.10	6 (0.013)	2.1	203 (0.472)	78.7
Average	13.9	4.49	0.35	28.3 (12186)	247 (0.574)	8.22	0.16	9 (0.022)	3.6	215 (0.500)	87.1
Wald.-Han. Walden x 100	+5%	-6%	-75%	-2%	-75%	-11%	-84%	-85%	-44%	-77%	-47%

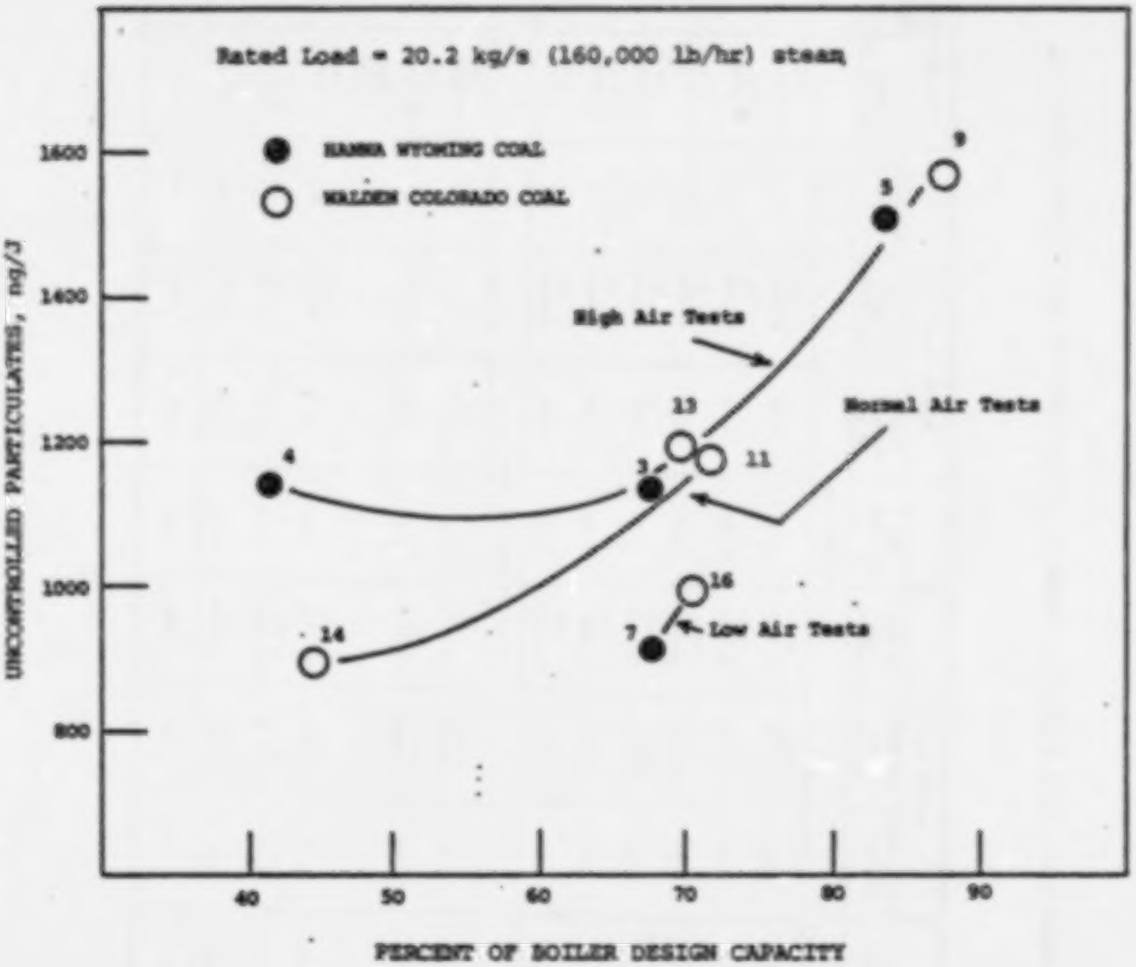


Figure 5.10-3. Uncontrolled particulate emissions vs. boiler load, Fremont Department of Utilities Unit 6.

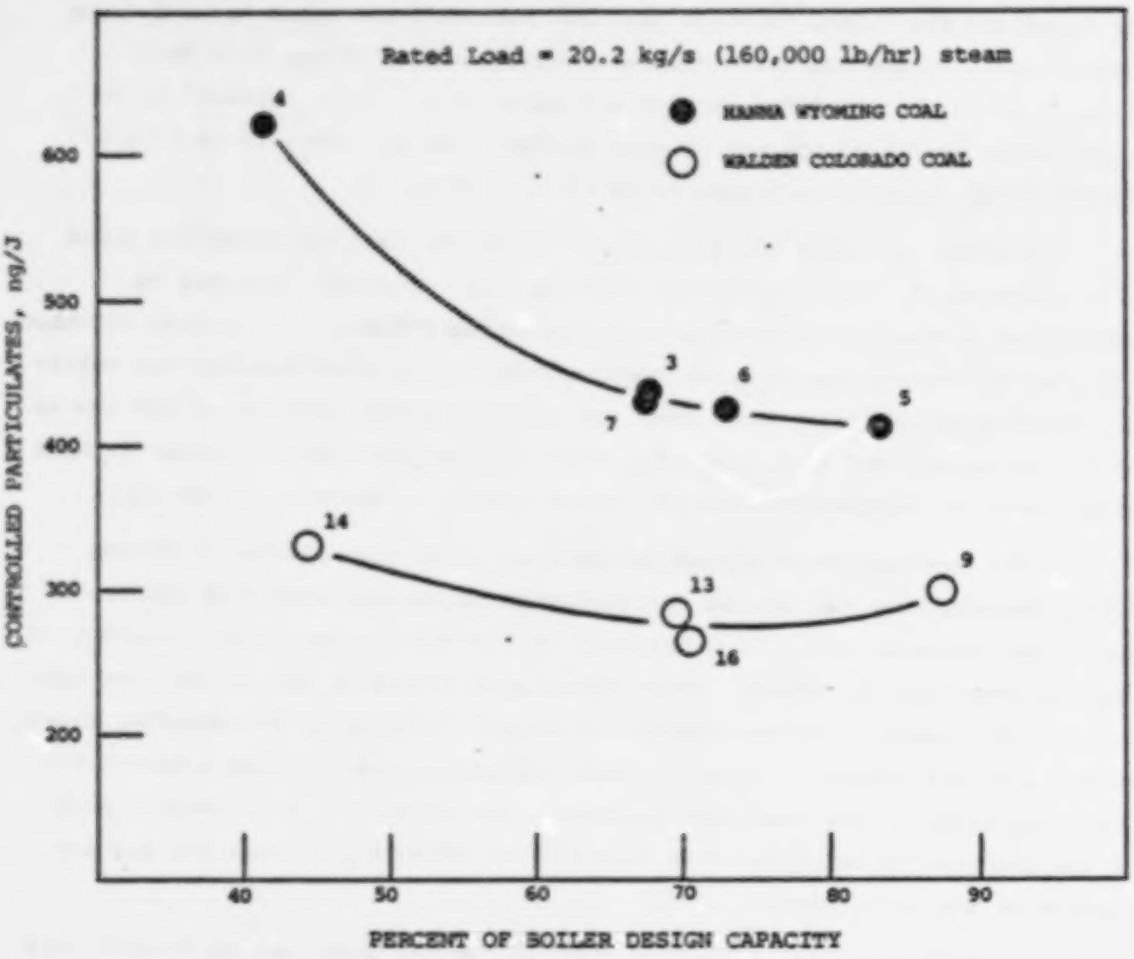


Figure 5.10-4. Controlled particulate emissions vs. boiler load, Fremont Department of Utilities Unit 6.

Of special interest when studying pulverized coal burning units is the percent of total ash carried over as emissions. To calculate the total ash input to the boiler, mass fraction of ash in the fuel is divided by the fuel's heating value. Expressed in metric units, the results is 2758 ng/J ash input for the Walden Colorado coal and 3629 ng/J ash input for the Hanna Wyoming coal. Comparing these figures with the ash emissions data from Figure 5.10-13, we concluded that at 85% capacity 17.2 kg/s ($136x10^3$ lb/hr steam) about 40-55% of the ash is carried over. At 50% capacity 10.1 kg/s ($80x10^3$ lb/hr steam) this figure is about 25 to 40%.

One way to reduce the fly ash carryover and thus the emissions would be to increase the sizing of the pulverized coal. However, this may be impractical because it is tied in with combustion efficiency. Another solution would be to increase the furnace cross sectional area thus reducing the vertical velocity of the combustion gases and allow a larger fraction of the ash to settle and be removed as bottom ash. This is also impractical because it adds to the cost of construction and may reduce thermal efficiency of the unit.

The dust collector outlet (controlled) emissions plotted in Figure 5.10-4 clearly show the average 36% reduction in particulates from burning the Walden Colorado coal. Also apparent is the normalizing effect inherent to cyclone type dust collectors. This normalizing effect is due to the fact that cyclone efficiency increases substantially with velocity of the entering gases. Boiler load and excess air both increase the particulate loading entering the collector while at the same time increasing gas velocity. As a result, much of the increase in emissions with load and the effects of excess air are not visible in the outlet data.

Cyclone type dust collectors such as the one installed on Fremont Unit 6 are designed for maximum boiler load where they operate at efficiencies in the 80 to 90% range (see Predicted Multiclone Efficiency from design data in Section 5.10.1). From Figure 5.10-5 where this unit's collector efficiency is plotted against load, we can project maximum load efficiency at 83-86% depending on the coal burned. At one-half load this number is cut by 20-30%. In other words, this type of collector is very inefficient at medium and low loads. This can be a real disadvantage where boilers are operated below peak loading over the majority of their cycle.

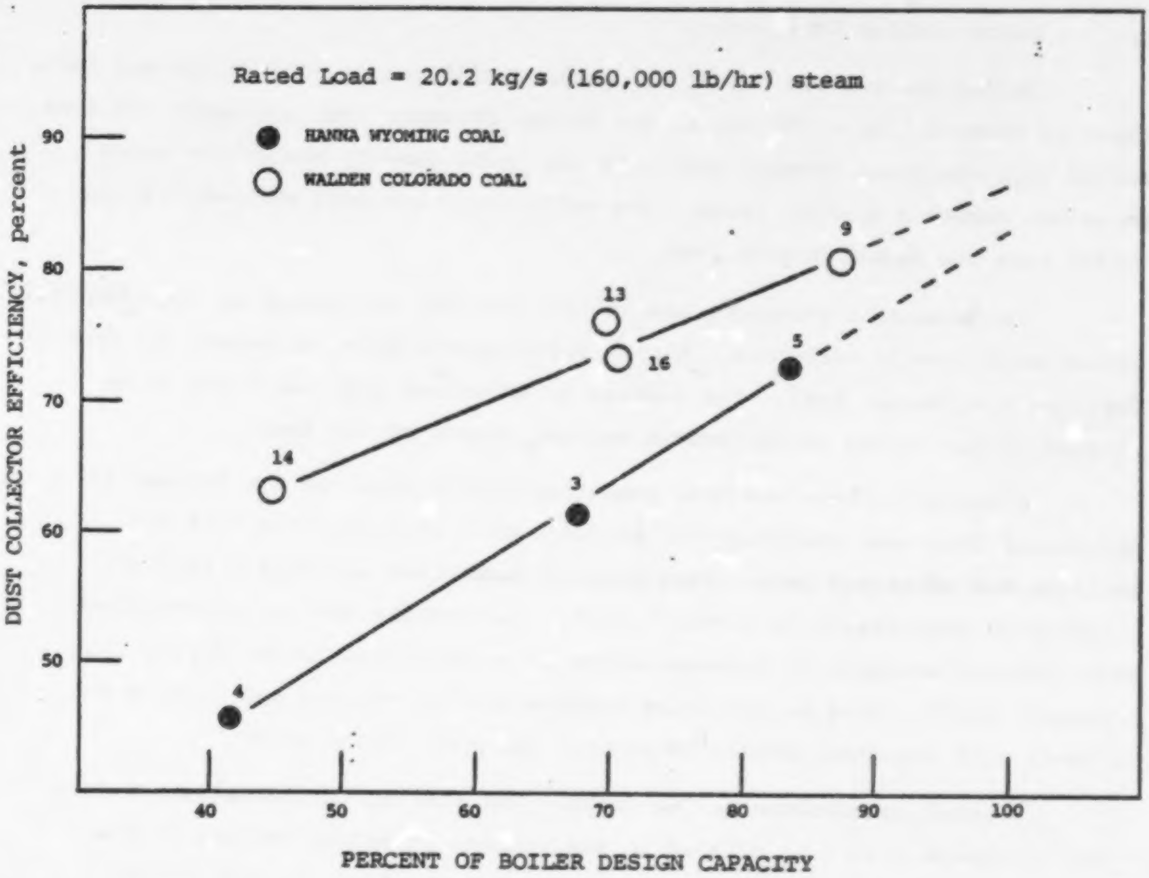


Figure 5.10-5. Multiclone dust collector efficiency vs. boiler load, Fremont Department of Utilities Unit 6.

The improved collector efficiency in handling Walden Colorado coal is quite evident. It may be due to larger average sizing of this pulverized coal stemming from a difference in its grindability, or it may result from agglomeration of the ash.

C. Sulfur Oxides Emissions--

Sulfur content was one of the primary differences between the two fuels fired at Fremont. On a HHV basis, the Walden Colorado coal contained 75% less sulfur than the Hanna Wyoming coal. As one would expect, the sulfur oxide emissions showed a similar trend. The Walden Colorado coal emitted 77% less sulfur than the Hanna Wyoming coal.

Variations in excess O_2 and boiler load did not appear to significantly effect sulfur oxide emissions. Figure 5.10-6 plots these emissions for both fuels against boiler load. The scatter in emissions data was found to be related to day-to-day variations in sulfur content of the fuel.

A sulfur balance was made comparing sulfur input to the furnace as determined from coal analysis with sulfur output as determined from ash analysis and emissions data. This data is summarized in Table 5.10-3 and illustrated graphically in Figure 5.10-7. The results are not inconsistent with previous attempts to balance sulfur in a coal-fired boiler during this program. Difficulties in obtaining representative coal and ash samples due to their ever changing properties account for much of the error.

Several conclusions can be drawn. The scatter in the emissions data shown in Figure 5.10-6 is related to the scatter in sulfur content of the coal, not experimental error, or excess O_2 as tests 2, 3, 6, and 7 might indicate.

There may be a correlation between excess O_2 and sulfur retention in the ash. Based on limited data, the sulfur retention appears to increase as excess O_2 is increased.

Finally, the sulfur retention was on the order of 5%, with the Walden Colorado coal appearing to retain a slightly lower percentage of the total sulfur in its ash.

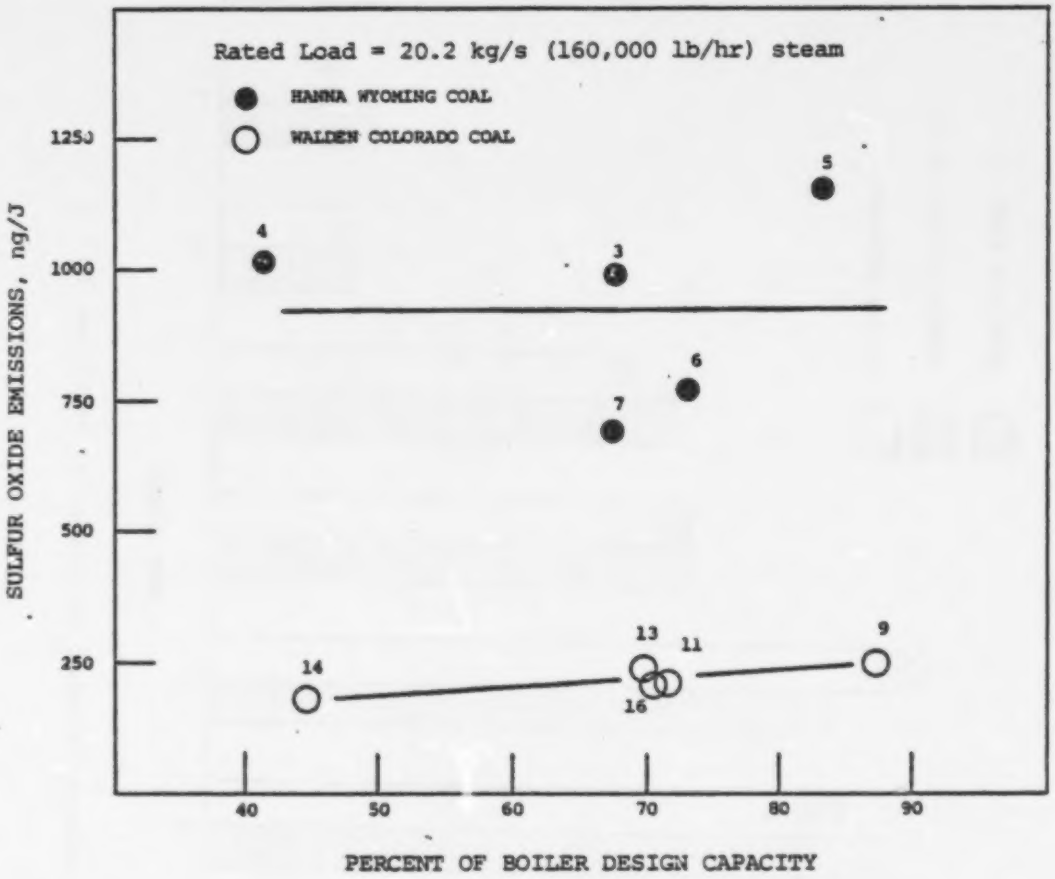


Figure 5.10-6. Sulfur oxide emissions vs. boiler load, Fremont Department of Utilities Unit 6.

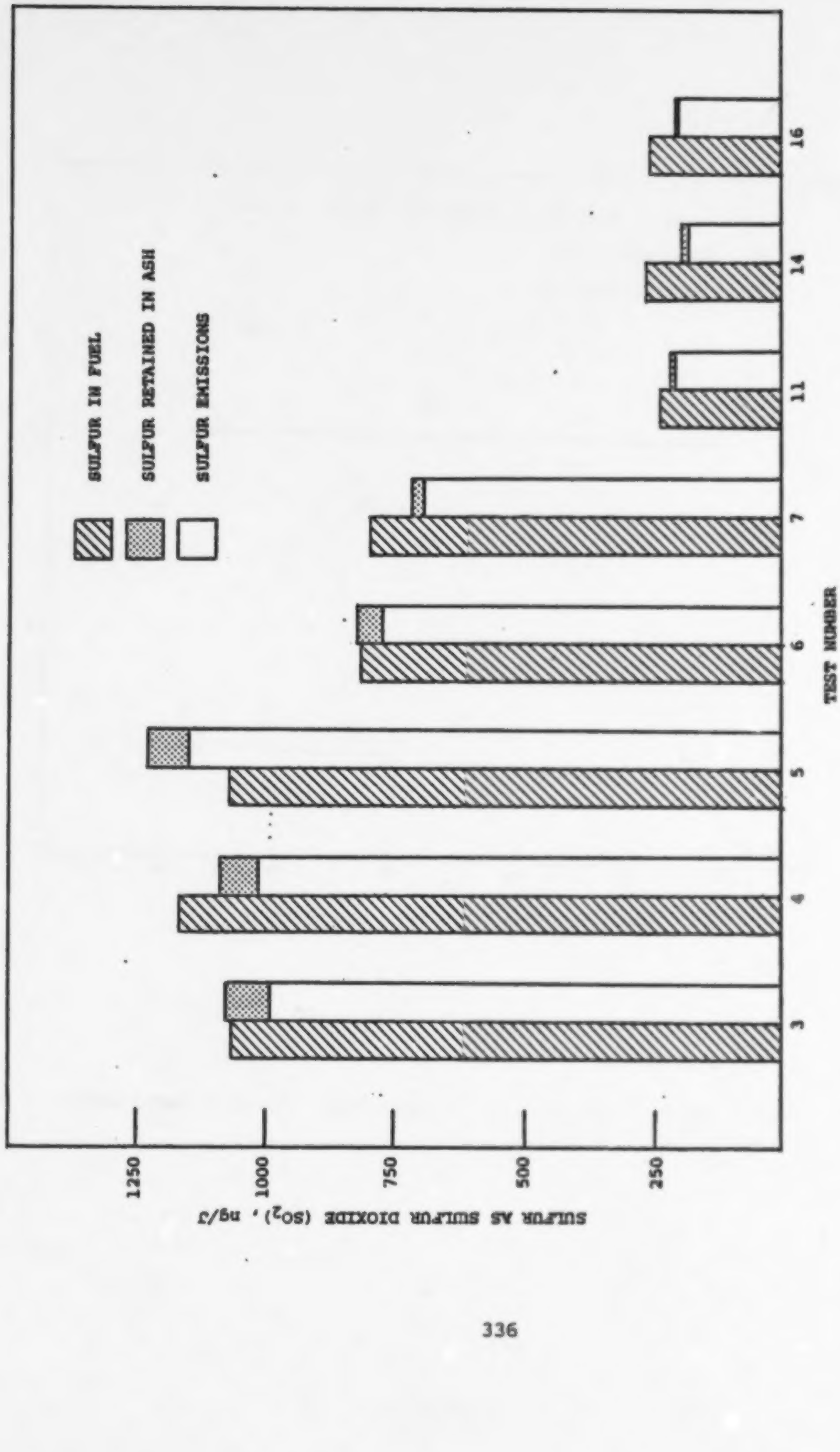


Figure 5.10-7. Sulfur balance, Fremont Department of Utilities Unit 6.

Sulfur trioxide was not plotted. It accounted for 0.38% of the total sulfur oxides when Hanna Wyoming coal was burned and over the range of O_2 levels studied was not a function of either load or excess O_2. When Walden Colorado coal was burned, the sulfur trioxide fraction varied from 0 to 9.5%. These variations could not be correlated with any of the test variables.

D. Nitric Oxide Emissions--

As seen in Table 5.10-2, the average nitric oxide emissions were 26% lower when burning Walden Colorado coal as compared to Hanna Wyoming coal. One reason for this may be found in the fuel analysis, Table 5.10-1, which shows the Walden Colorado coal contained 25% less fuel bound nitrogen.

Fuel-bound nitrogen is the primary source of nitric oxide from coal fired boilers. If we assume that all of the nitric oxide was formed from fuel-bound nitrogen, then we find that 19.9% of the Hanna Wyoming coals' nitrogen and 19.4% of the Walden Colorado coals' nitrogen was converted to nitric oxide.

Nitric oxide increased with load as shown in Figure 5.10-8. Test numbers 3, 4, and 5 can be considered to be at constant excess O_2. Here, a 10% increase in load resulted in a 7.5% increase in nitric oxide emissions at 80% load. It should be noted that low load tests 4 and 14 were run with only two of the units four burners in service. This is normal low load configuration. The two burners taken out were diagonally opposed so that both mills could remain in operation, each feeding one burner.

Nitric oxide increased with excess O_2 as shown in Figure 5.10-9. For this series of tests, boiler load was held constant while the air/fuel ratio was varied at 15 minute intervals. On the average, nitric oxide was found to increase by 16 ng/J, or about 10% for each 1% increase in excess O_2. This data is contained in Table 5.10-4.

E. Carbon Monoxide and Hydrocarbon Emissions--

Under normal operating conditions, carbon monoxide remained insignificant at values of less than 20 ppm for both fuels. However, this unit was fired at higher than necessary excess O_2 levels.

TABLE 5.10-4. EMISSIONS SUMMARY FOR SPECIAL TESTS, FREMONT DEPARTMENT OF UTILITIES, UNIT 6

TEST NO.	LOAD kg/s	LOAD % Cap.	O_2 %	CO Dry, ppm	NO Dry, ppm	NO ng/J
8	13.8	63	4.10	6	490	186
	(Hanna Wyoming Coal)		4.05	13	488	186
	(7/29/76)		4.40	13	515	196
			4.90	13	525	200
			4.10	13	479	182
			3.75	7	463	176
			3.40	15	450	171
10	17.8	88	5.45	13	469	177
	(Walden Colorado Coal)		5.30	13	464	175
	(8/18/76)		4.80	12	443	167
			4.50	22	431	163
			4.15	59	420	158
12	13.6	68	4.40	11	369	139
	(Walden Colorado Coal)		3.90	8	353	133
	(8/20/76)		3.50	19	324	122
			3.15	38	325	123
15	8.9	45	4.10	13	370	140
	(Walden Colorado Coal)		3.85	14	399	150
	(8/22/76)		3.35	36	398	150
			2.70	148	--	--

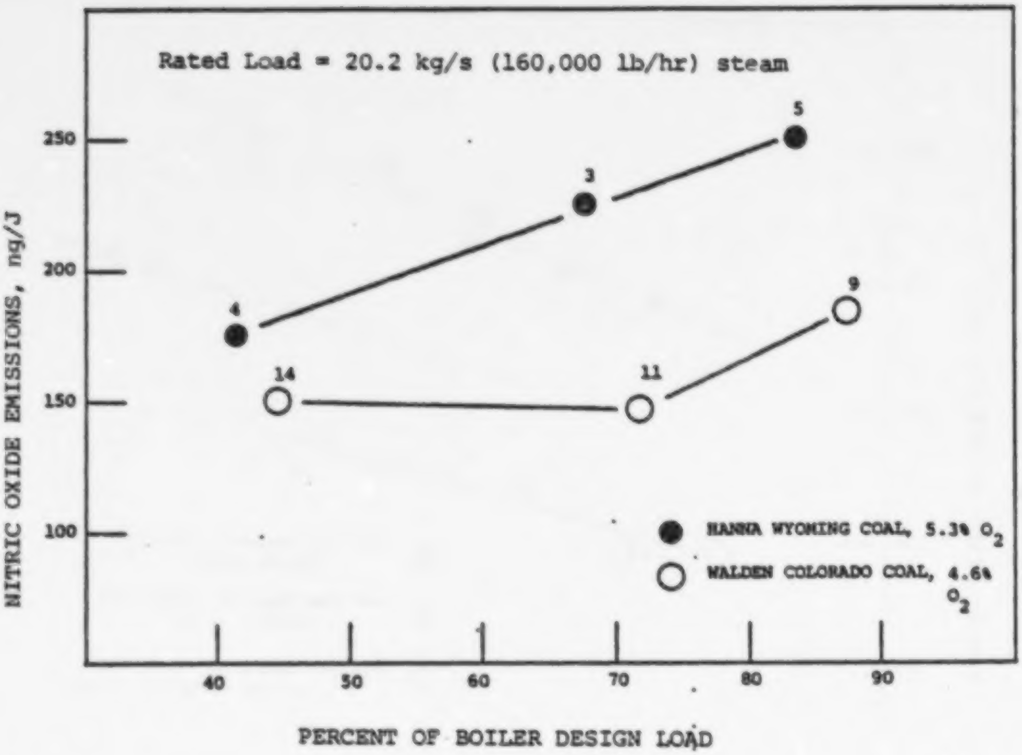


Figure 5.10-8. Nitric oxide emissions vs. boiler load, Fremont Department of Utilities Unit 6.

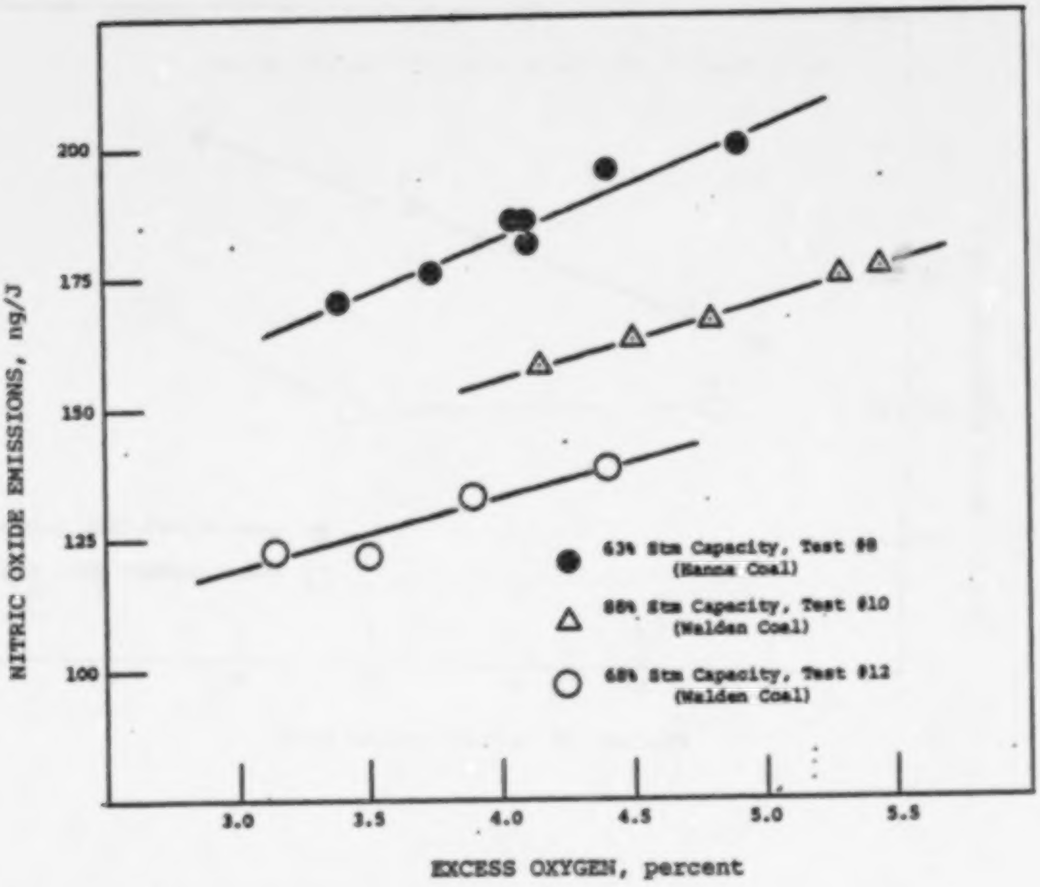


Figure 5.10-9. Nitric oxide emissions vs. excess oxygen, Fremont Department of Utilities Unit 6.

During tests 10, 12, and 15 when air/fuel ratio was varied in increments, carbon monoxide was monitored to determine the point at which it would begin to rise. The data is shown in Figure 5.10-10. At low and medium loads this point was reached at 3.9% excess O_2. For high loads, carbon monoxide began to increase below 4.8% excess O_2. According to the control room O_2 monitor, which was closer to the furnace than ours, an increase in carbon monoxide occurred as the excess O_2 dropped below 3.0% for all three loads.

By sampling from each side of the boiler separately it was discovered that the CO was being formed much sooner on the west side than on the east. The following data illustrates this point:

	West Side	East Side
Excess O_2	2.22%	3.55%
Carbon Monoxide	280 ppm	15 ppm

(Data from test 12, August 20, 1976)

According to B&W, the burners should be able to operate continuously at 3% excess O_2 without CO formation. It is concluded that the present operation at 3.8% excess O_2 could be reduced to 3.0% if the fuel/air ratio were balanced on both sides. A substantial savings in operating cost through improved efficiency would result.

Hydrocarbon emissions were measured but showed no significant correlation with load or excess O_2. Part of the problem in measuring hydrocarbons was a contaminated heated sample line from which background emissions had to be subtracted. These varied with time and flow rate. The net hydrocarbon emissions measured ranged from 33 to 161 ppm and were about 30% lower for the Walden Colorado coal. This data is contained in Table 5.10-2.

5.10.4 Boiler Efficiency

Table 5.10-5 compares boiler efficiencies while burning the Hanna Wyoming and Walden Colorado coals. The largest heat losses are moisture + H_2 and dry gas losses. The fuel moisture losses did not vary significantly from one fuel to the other. The dry gas losses were the main variables. The overall unit efficiency was slightly higher when burning the Walden Colorado coal due to lower dry gas losses.

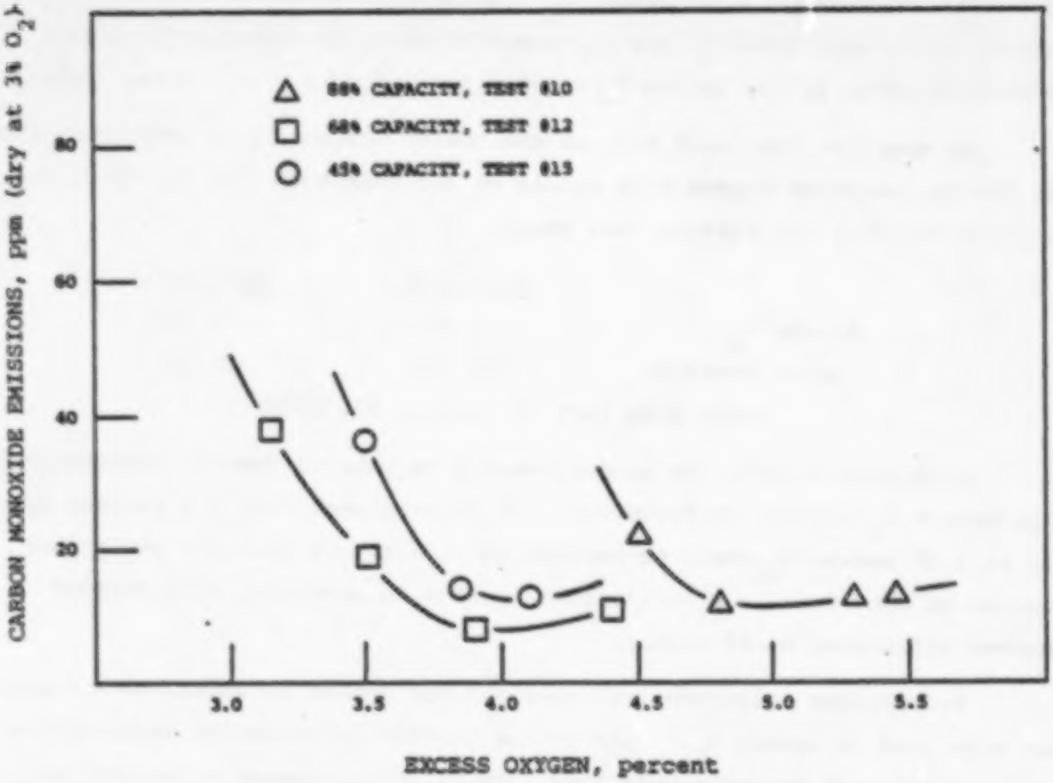


Figure 5.10-10. Carbon monoxide emissions vs. excess oxygen at three boiler loads, Fremont Department of Utilities Unit 6, Walden Colorado coal.

TABLE 5.10-5. BOILER EFFICIENCY SUMMARY, FREMONT DEPARTMENT OF UTILITIES, UNIT 6

	HANNA WYOMING					WALDEN COLORADO				
Test No.	3	4	5	6	7	9	11	13	14	16
Test Load										
kg/s	13.6	8.3	16.9	14.7	13.6	17.5	14.4	14.2	8.9	14.2
Percent of Capacity	67.7	41.3	83.4	73.0	67.6	87.4	71.8	69.8	44.4	70.4
Stack O_2 (% Dry) *	4.9	4.8	5.4	3.6	3.3	5.2	3.8	5.0	3.8	3.4
Stack CO (ppm)	11.0	17.0	20.0	18.0	17.0	14.0	12.0	10.0	13.0	61.0
Stack Temp. (°K/°F)	443/338	434/322	447/346	437/328	434/321	442/337	429/314	435/323	430/315	437/328
Ambient Air Temp. (°K/°F)	315/108	311/100	309/96	307/94	314/106	309/97	306/92	306/91	308/95	311/100
Corr. Stack Temp. (°K/°F)	434/321	427/310	442/336	433/320	425/305	437/327	426/307	431/316	426/307	431/316
Boiler Heat Bal. Losses (%)										
Dry Gas	5.99	5.68	6.40	5.54	5.05	6.12	5.26	5.72	5.21	5.21
Moisture + H_2	5.64	5.61	5.67	5.63	5.60	5.76	5.71	5.73	5.71	5.73
Moisture in Air	0.14	0.14	0.15	0.13	0.12	0.15	0.13	0.14	0.12	0.12
Unburned CO	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.01	0.02
Combustibles	0.11	0.13	0.05	0.07	0.07	0.04	0.02	0.04	0.11	0.07
Radiation	0.59	0.97	0.48	0.55	0.59	0.46	0.56	0.57	0.90	0.57
Boiler Efficiency	87.52	87.46	87.24	88.07	88.56	87.47	88.32	87.79	87.95	88.28

* Stack O_2 measured at dust collector inlet

Excess oxygen played an important role (Figure 5.10-11). Lowering the excess O_2 by 1% raised the unit overall efficiency by about 0.5%. When boiler load was raised from 70 to 85% of capacity, the overall efficiency dropped 0.3% due to greater dry gas losses. When boiler load was dropped from 70% to 45%, and two burners were taken out of service, the overall unit efficiency dropped somewhat due to radiation loss accounting for a larger percentage of the total heat output. Moisture in the air, unburned CO and combustibles in the ash did not play a significant part in shaping the overall boiler efficiency.

5.10.5 Operational Problems and Observations

Unit #6 of Fremont Department of Utilicies was designed for a subbituminous Kansas coal. When the switch was made to Hanna-Rosebud Wyoming coal in an attempt to meet air pollution regulations, several operational problems developed. Full steam capacity could not be obtained. Because of day-by-day variations in the coal properties, the steam capacity of Unit #6 was sometimes reduced by as much as one-third of design capacity. Unloading this coal created a dust problem in the summer. In the winter, it froze in the coal cars and was difficult to remove.

The switch to Colorado coal was made during our testing because of its lower ash, lower sulfur, lower price and more feasible shipping point. This coal proved to be cleaner burning. Design steam capacity was easily met. When mixed with the Wyoming coal there was less problem maintaining load. Following our test program at Fremont, the remaining Wyoming coal was burned by mixing it with the Colorado coal.

Although the Colorado coal burned well, it was even harder to unload than the Wyoming coal. The dust problem was very bad in the summer. In the winter, there were times when only four cars could be unloaded per day because of freezing.

During testing, when the Colorado coal was burned, the mills were not pulverizing the coal as well as they should have been. This problem was later corrected by adjustments to the mills. It is possible that the reduced

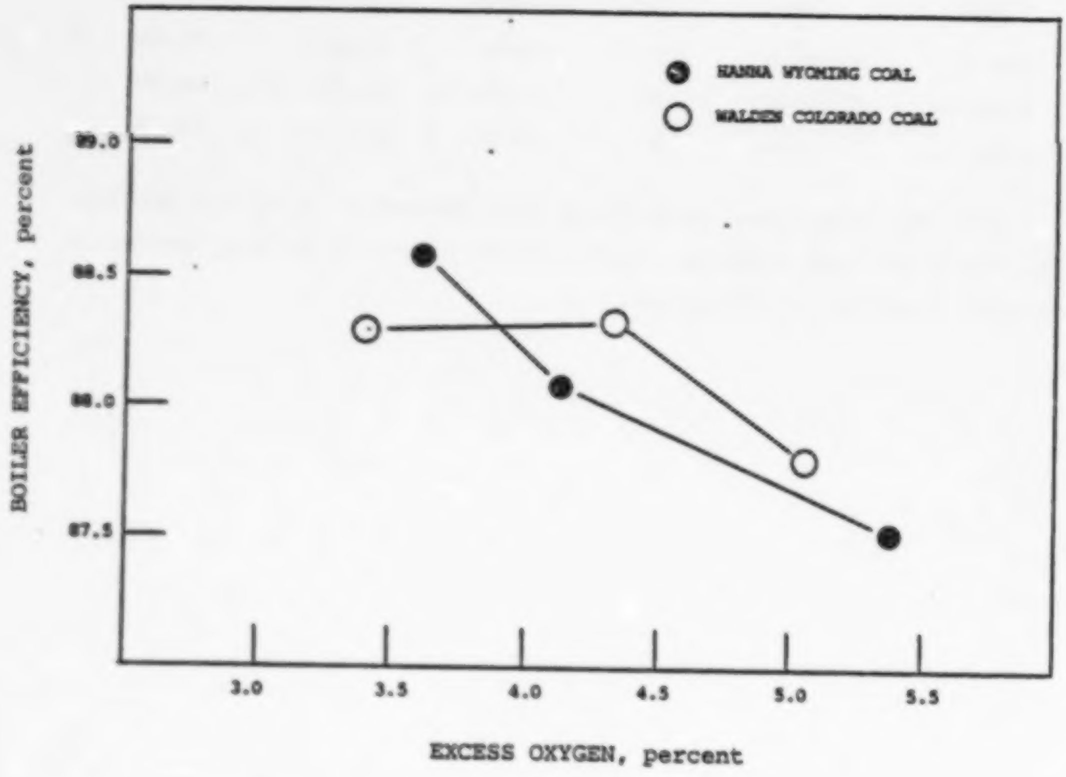


Figure 5.10-11. Boiler efficiency vs. excess O_2, Fremont Department of Utilities Unit 6.

controlled particulate emissions obtained when burning the Colorado coal were due to a coarser fuel sizing rather than any other fuel property. A table of the coal sizing tests follows:

Date	Coal	Mill	<50 Mesh	>100 Mesh	>200 Mesh
8/4/76	Wyoming	A	0.4%	95.6%	77.4%
8/18/76	Colorado	A	4.0%	86.0%	58.3%
8/18/76	Colorado	B	1.3%	92.7%	64.7%

Also during testing, peak loads were limited by a cooling problem with the Unit #6 steam turbine. This problem prevented us from testing at peak boiler load with the Colorado coal.

APPENDIX A

INDUSTRIAL-SIZED BOILER POPULATION SURVEY

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A.1 INTRODUCTION

The purpose of this section of the western coal study which this Appendix covers was to survey and screen the small and intermediate-sized coal-fired boilers in the United States in order to determine the feasibility of converting a portion of them to a low-sulfur western coal as a means of reducing sulfur oxides emissions. The American Boiler Manufacturers Association (ABMA) sales data which included 362 units for 1965-1974 was used to obtain a more detailed geographical distribution, both by population and capacity, of coal-fired boilers in the range 1.3 to 38 kg/s [10,000 to 300,000 lb/hr (pph)] steam. The results of this survey show that the heaviest concentration of coal-fired units is in the midwest around the Great Lakes. This will then be the area where the maximum potential SO_x reduction exists.

In addition to the boiler survey, an analysis was made of the geographical distribution of sulfur in coals used as industrial boiler fuel. This data was then used with the boiler population to arrive at an estimate of the maximum possible SO_x reduction achievable by changing fuel to low sulfur western coal. The impact of this reduction was demonstrated for four areas of the United States and with four coals which are typical of the largest western-coal-producing regions. The results indicate that SO_x reductions in emissions from coal-fired industrial boilers of 46% to 78% could theoretically be realized on a nationwide basis, and reductions of 53% to 81% for the midwestern-Great Lakes region by using western coal.

An informal survey was conducted in order to determine current western coal users. One hundred and eleven boiler owners and operators in Minnesota, Wisconsin, Iowa, Nebraska, Michigan, Indiana, Missouri, and Illinois were contacted. Information was gathered on the following:

- Installed boiler population and geographical distribution
- Western coal users and operational experience with particular firing equipment
- Conversion from coal to gas and/or oil
- Potential hosts for boiler testing

A study of the supply variables made it apparent that the two states of Wyoming and Montana are the only western states that are in a position to supply coal to the midwestern and eastern parts of the country during the next ten years. The factors that were taken into consideration were:

- Current production from specific sources
- Production trends and costs
- Shipping costs
- Mine capacities

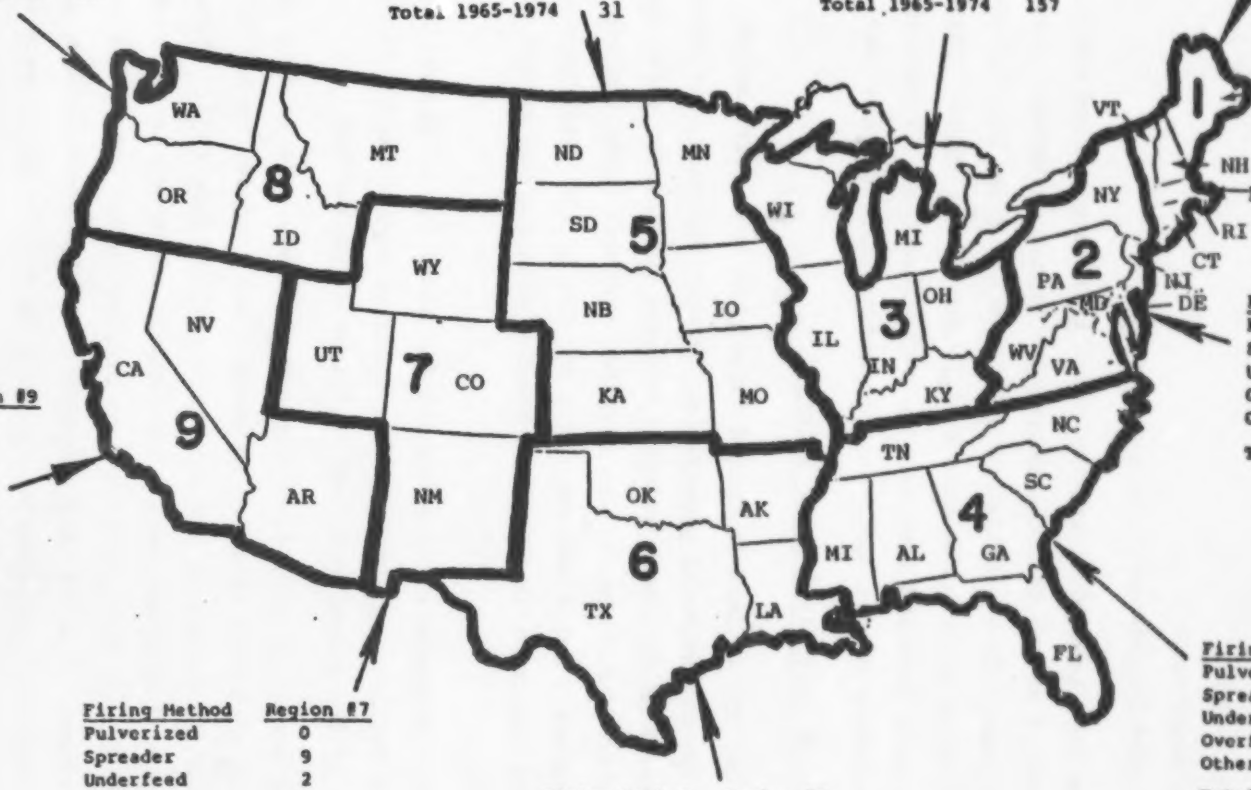
Analyses of the coal from all of the major producing areas in Wyoming and Montana have been obtained. These typical coal analyses were then compared to the combustion requirements for the individual firing types to arrive at an estimate of the difficulty that would be encountered in switching to the western coal.

The data gathered during the first phase of the program indicate that a conversion to western coal can be an effective SO_x emission control technique for most types of coal combustion systems. However, some penalties are involved with unit performance and efficiency. Furthermore, it seems likely that the supply of western coal, especially from Wyoming and Montana, can be made available in midwestern markets at competitive prices.

A.1.1 Boiler Survey

Figure A-1 contains ABMA sales data for boilers sold between 1965 and 1974. The data have been sorted according to the following categories:

- Firing Type (pulverized, spreader stoker, overfed stoker, underfed stoker, or other)
- Capacity [1.3 to 38 kg/s (10,000 to 300,000 lb/hr pph) steam]
- Year of Sale (1965-1974)


WA
OR
8
ID
MT
WY
UT
7
CO
NV
CA
9
AR
NM
ND
MN
SD
5
NB
IO
KA
MO
OK
AK
6
TX
LA
WI
MI
IL
3
IN
OH
KY
TN
MI
AL
4
GA
SC
NC
FL
VT
NY
PA
2
WV
VA
MD
DE
NJ
CT
RI
MA
NH
1
ME

Firing Method	Region #8
Pulverized	1
Spreader	5
Underfeed	1
Overfeed	2
Other	2
Total 1965-1974	11

Firing Method	Region #5
Pulverized	2
Spreader	22
Underfeed	0
Overfeed	4
Other	3
Total 1965-1974	31

Firing Method	Region #3
Pulverized	13
Spreader	70
Underfeed	4
Overfeed	27
Other	43
Total 1965-1974	157

Firing Method	Region #1
Pulverized	0
Spreader	1
Underfeed	0
Overfeed	1
Other	0
Total 1965-1974	2

Firing Method	Region #9
Pulverized	0
Spreader	0
Underfeed	0
Overfeed	0
Other	2
Total 1965-1974	2

Firing Method	Region #2
Pulverized	8
Spreader	31
Underfeed	10
Overfeed	8
Other	17
Total 1965-1974	74

Firing Method	Region #7
Pulverized	0
Spreader	9
Underfeed	2
Overfeed	0
Other	1
Total 1965-1974	12

Firing Method	Region #6
Pulverized	0
Spreader	4
Underfeed	0
Overfeed	0
Other	5
Total 1965-1974	9

Firing Method	Region #4
Pulverized	6
Spreader	34
Underfeed	9
Overfeed	5
Other	10
Tptal 1965-1974	64

Figure A-1. Regional boundaries used in Table A-1.

- Geographical Location (1973-1974 have full zip code, 1970-1972 have first three digits of zip code, and 1965-1970 have a one-digit zip code)
- Primary and Alternate Fuel (units that use coal or lignite as a primary fuel or units that can fire coal or lignite as an alternate fuel)
- Domestic Sale
- Stationary Unit
- Standard Industrial Classification Code

These boilers have been located on the map shown in Figure A-1 and compiled in Table A-1 in such a manner that the geographic impact of western coal conversion can be seen. In a similar manner, Table A-2 gives the capacity of the coal-fired units distributed into regions and firing types. This survey presents a more detailed look at this particular class of unit than is available from either Walden (Ref. A-1) or the Battelle studies (Ref. A-2).

Population of Coal-Fired Units Surveyed

Region 3 had 157 boilers installed during the nine year period. This represents about 44% of the total population. Within Region 3, the distribution among firing types is as follows: pulverized units account for 8.3%; spreader stokers, 44.5%; overfed stokers, 17.2%; underfed stokers, 2.5%; and other units, 27.4%. Regions 2 and 4 had about 20% and 18% of the total population, respectively. The remaining 18.5% of the total population was spread over the other regions.

Nationally, spreader stokers account for about 50% of the units sold during the period followed by 20% for other types of coal firing, 13% for overfed stokers, 9% for pulverized, and 7% for underfed stokers.

The total number of coal-fired boilers that have been sold in the last nine years in this size category is small (362) compared to the total number existing in the United States which are still firing coal. Ehrenfeld (Ref. A-1) estimated that there were 5,239 boilers installed in the country in the size range 1.3 to 35 kg/s (10,000 to 250,000 lb/hr) steam that could burn coal. The number of units that actually fire bituminous coal or lignite is considerably smaller. For example, in 1973, 36 overfed units were sold;

TABLE A-1. NUMBER OF UNITS SOLD FROM 1965 to 1974 BY REGION

Categories	Geographic Regions* 1	2	3	4	5	6	7	8	9	Total
Other		17	43	10	3	5	1	2	2	83
Pulverized		8	13	6	2			1		30
Spreader Stoker	1	31	70	34	22	4	9	5		176
Underfed		10	4	9			2			25
Overfed	1	8	27	5	4	—	—	3	—	48
Total	2	74	157	64	31	9	12	11	2	362
% of Total	0.6	20.4	43.4	17.7	8.5	2.5	3.3	3.0	0.6	

*Geographic Region (by number code)

1. New England States
   Connecticut, Maine, New Hampshire, Massachusetts, Rhode Island, Vermont
2. Mid-Atlantic States
   Delaware, Maryland, New Jersey, New York, Pennsylvania, Virginia, West Virginia
3. East-North-Central States
   Illinois, Indiana, Kentucky, Michigan, Ohio, Wisconsin
4. South-Atlantic States
   Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, Tennessee
5. West-North-Central States
   Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota
6. West-South-Central States
   Arkansas, Louisiana, Oklahoma, Texas
7. Rocky Mountain States
   Colorado, New Mexico, Utah, Wyoming
8. Northwestern States
   Idaho, Montana, Oregon,
9. Southwestern States
   Arizona, California, Nevada

however, 33 of these units were specifically designed to burn wood. Overfed and spreader stoker units are two categories of firing types where there appears to be a significant wood-burning contribution. Typically, these units are installed in the wood and paper processing industries where the waste wood and paper products are burned as boiler fuel. However, such units will fire bituminous coal when there is insufficient waste wood to meet load demands.

The pulverized coal firing type and the underfed stoker firing type are limited to bituminous coal and lignite firing.

The "other" category includes cyclone units at the larger end of the size range, above 25.2 kg/s (200,000 lb/hr) steam. The smaller units in the "other" category include vibrating grate, reciprocating, and oscillating grate stokers. Some of these units may be equipped with a system whereby the ash is blown off the water-cooled grate with either steam or air.

More detailed information about grate design is not available from the ABMA records. For example, spreader stokers may be equipped with traveling grates or dumping grates. Some smaller overfed units are equipped with water-cooled grates; however, this is not common.

Capacity of Coal-Fired Units Surveyed

Table A-2 gives the steam capacity in thousands of pounds per hour for all of the coal-fired boilers in the size range 1.3 to 38 kg/s (10,000 to 300,000 lb/hr) steam. Inspection of the data indicates that the capacities of the units sold closely follows the population distribution for both firing categories and geographic regions. In Region 3, spreader stokers account for 49.4%; other units, 24%; pulverized, 17.1%; overfed, 8.8%; and underfed, 0.73% of the total capacity of the region. Again, the overall capacity distribution for the nine regions follows population distribution. Region 3 has 41.3% of the total followed by Region 2 at 16.8%, Region 6 at 4.7%, and Regions 9 and 1 at 0.5% and 0.25%, respectively.

TABLE A-2. CAPACITY [kg/s (10^3 lb/hr) STEAM] OF COAL-FIRED UNITS SOLD FROM 1965 TO 1974 BY GEOGRAPHIC REGION

Firing Category	Geographic Regions 1	2	3	4	5	6	7	8	9	Total
Other		155 (1,230)	322.5 (3,562)	117 (931)	30.3 (240)	100.8 (801)	25.3 (200)	34.7 (275)	22.5 (178)	934.5 (7,417)
Pulverized		191 (1,516)	318 (2,524)	167.5 (1,329)	56.7 (450)			31.4 (250)		764.5 (6,069)
Spreader Stoker	3.9 (30)	327 (2,598)	917 (7,281)	355.3 (2,821)	395.3 (3,137)	109.7 (870)	139.7 (1,110)	128.1 (1,020)		2,376.7 (18,867)
Underfed		30.3 (241)	13.6 (108)	29.7 (197)	51 (405)		3.9 (31)			72.8 (577)
Overfed	7.5 (60)	94 (429)	163 (1,295)	46.7 (370)				20.8 (245)		353.3 (2,804)
Total	11.4 (90)	757.5 (6,014)	1,860.6 (14,770)	711.4 (5,648)	533 (4,232)	210.6 (1,671)	168.9 (1,341)	225.6 (1,790)	22.5 (178)	4,501.7 (35,734)
Percent of Total	0.25	16.8	41.3	15.8	11.8	4.7	3.8	5.0	0.5	

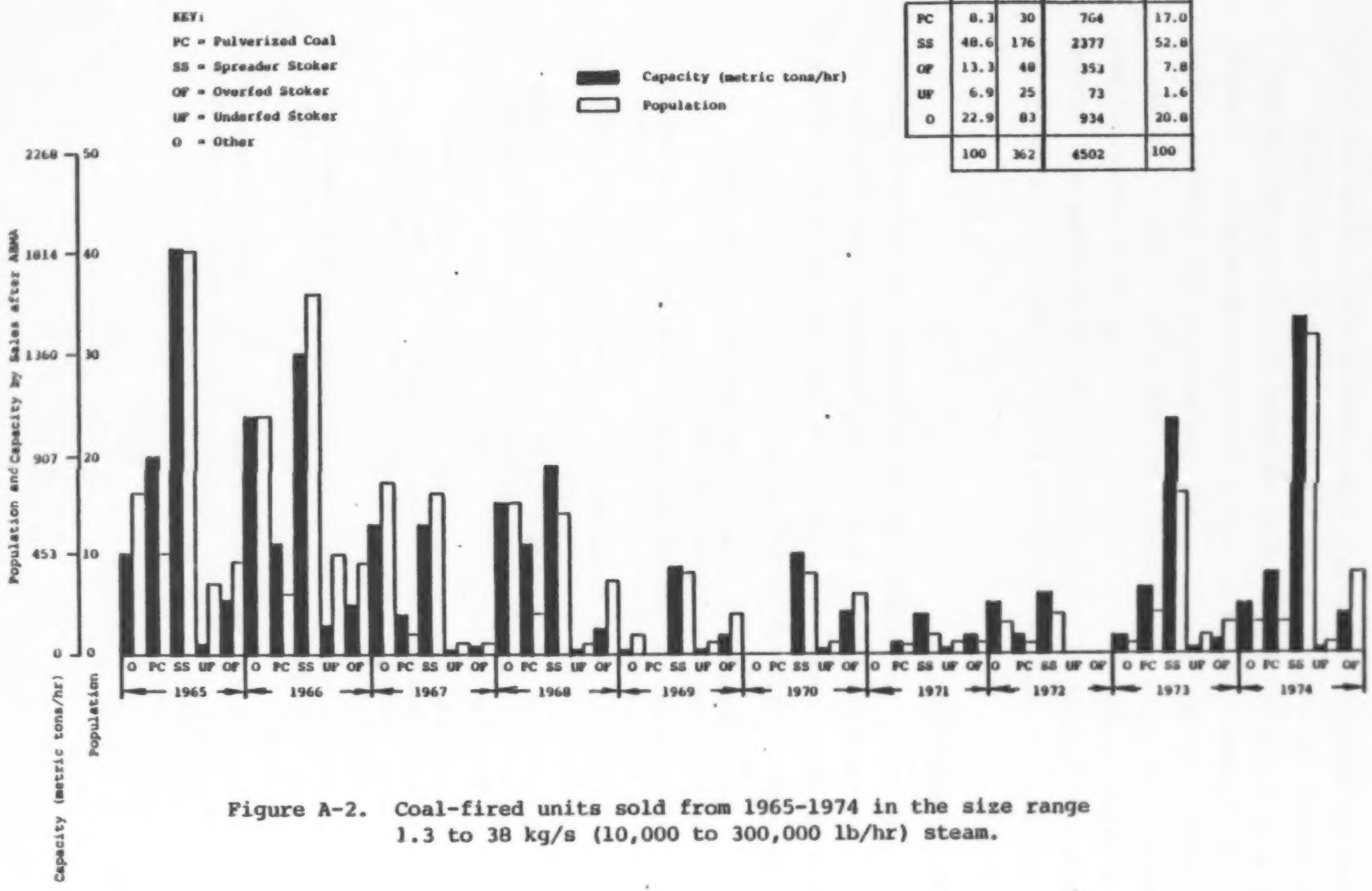
Sales Trends

Figure A-2 contains the 1965-1974 ABMA sales data for coal-fired units in the size range 1.3 to 38 kg/s (10,000 to 30,000 lb/hr) steam. The data are plotted by year as population and total steam capacity for the five firing types. It can be seen that boiler sales have declined steadily from 1965 to a low point in 1971. Beginning in 1973, however, there was a general increase in sales with spreader stoker sales approaching 1966 sales levels. Spreader stokers represent the largest single firing type, both by number and total capacitv. Pulverized-coal-fired units are predominantly the larger units above 25.2 kg/s (200,000 lb/hr) steam. This becomes obvious when population data and capacity data for pulverized coal units are compared. Spreader stoker units cover the entire size range of interest for this study with units as small as 1.3 kg/s (10,000 lb/hr) steam and as large as 28 kg/s (300,000 lb/hr) steam. The spreader stoker appears to be the unit of choice for most industrial coal-fired installations. Spreader stokers are also found in small utilities where they are used as peaking units.

For the ten-year period, the sales of each firing type relative to each other has remained roughly constant. During years of heavy sales, the spreader stoker has outsold all other types. Over this period, spreader stoker sales accounted for 49% of all units by population and 53% by capacity. The next largest category is the other firing types which account for 23% of the units by population and 21% by capacity. Overfed and underfed units combined represent 20% of the population, but only 9% of the capacity. Finally, the pulverized-coal-firing category contains 8% of the population and 17% of the capacity.

Design Trends

The versatility of the spreader stoker has made it the preferred firing method over the years and this trend appears to be continuing with even greater strength. The recent sales increase in coal-fired equipment has been dominated by the spreader stoker. The data also show a trend toward larger spreader stokers. One reason for the popularity of the spreader stoker



TOTALS

	%	No. of Units	kg/s Steam	%
PC	8.3	30	764	17.0
SS	48.6	176	2377	52.8
OF	13.3	48	353	7.8
UF	6.9	25	73	1.6
O	22.9	83	934	20.8
	100	362	4502	100

Figure A-2. Coal-fired units sold from 1965-1974 in the size range 1.3 to 38 kg/s (10,000 to 300,000 lb/hr) steam.

is that they are capable of burning a wide range of coals, from high ranked eastern bituminous to lignite, as well as many byproduct waste fuels. Spreader-stoker firing has a very quick response to load changes and the turndown range extends from 20% of full load to maximum capacity. Traveling grates remain the most popular grate configuration for spreader-stoker-fired boilers rated higher than 9.4 kg/s (75,000 lb/hr) steam. They are designed to handle a wide range of coals as well as process wastes and municipal refuse. In view of this flexibility and the fluctuating coal economy, the traveling grate is expected to be the system of choice for at least the next five years.

New Developments

It is difficult to estimate the environmental and economic impact of potential developments on this boiler size category. Some examples of these new developments whose effect may be to increase the total capacity of this size range or to decrease it are given below:

- Greatly expanded in-plant electrical generation would increase the size range capacity.
- Deregulation of natural gas prices would serve to increase the size range capacity by a reconversion to coal firing.
- Further oil price increases would increase the size range capacity in the same way gas deregulation would.
- Legislation restricting the use of natural gas for process units would increase the number of units and the capacity in the size range.
- Large-scale coal gasification and/or liquefaction would tend to decrease the coal-fired capacity of the size range; however, this development is at least ten years in the future.
- Increased commercial electrical generation with resultant lower energy rates would not measurably affect this size category of boiler.
- Environmental legislation aimed at sulfur, particulates, and NO_x, would probably not measurably affect this size category due to the severity of the energy constraints.

REFERENCES FOR APPENDIX A

A-1 Ehrenfeld, J. R., et al., "Systematic Study of Air Pollution from Intermediate Size Fossil-Fuel Combustion Equipment," Final Report, Contract CPA 22-69-85, Walden Research Corporation, July 1971.

A-2 Locklin, D. W., et al., "Design Trends and Operating Problems in Combustion Modification of Industrial Boilers," Battelle Final Report for EPA Grant No. R-802402, April 1974.

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APPENDIX B

GEOGRAPHICAL COAL SULFUR DISTRIBUTION AND IMPACT ON AIR QUALITY OF FUEL SWITCHING TO WESTERN COAL

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B.1 BOILER CAPACITY

The total output capacity of boilers in the size range 1.3 to 32 kg/s (10 to 250×10^3 lb/hr) steam was estimed by Locklin (Ref. B-1) to be 1.15×10^{15} MJ/hr for the 1.3 to 12.6 kg/s (10 to 100×10^3 lb/hr) steam range and 8.44×10^{14} MJ/hr for the 12.7 to 32 kg/s (100 to 250×10^3 lb/hr) steam range. These figures were based on the 1971 estimate of Ehrenfeld (Ref. B-2), updated for sales during the period of 1967 to 1974.

The percent capacity as coal-fired units was given in Reference B-1 as 10% for the 1.3 to 12.6 kg/s range and 19% for the 12.7 to 32 kg/s range. Thus the total heat capacity installed for coal is estimated to be:

$$Q_{1.3-12.6} = 1.01\times10^{18} \text{ MJ/yr}$$

$$Q_{12.7-32} = 1.41\times10^{18} \text{ MJ/yr}$$

For a heating value of 23.2 MJ/kg (10,000 Btu/lb), the coal consumption in these boilers is:

$$M_{1.3-12.6} = 43.3\times10^{6} \text{ metric tons/yr}$$

$$M_{12.7-32} = 60.46\times10^{6} \text{ metric tons/yr}$$

B.2 CURRENT COAL SULFUR DISTRIBUTION

The current distribution of sulfur in coal was estimated from seam analyses given in the Keystone Coal Manual (Ref. B-3), from mine analyses in the same source, and from mine analyses summarized by Reference B-4. For western coals, only the mine analyses were used since they were a more reliable indication of available coals. For midwestern and eastern coal, the seam analyses were used since the area is heavily mined and better characterized. Where seam reserve estimates were available, the sulfur percentage was weighted by these estimates. For the western coal, the sulfur percentage was weighted by mine capacity.

Table B-1 summarizes the results obtained by this method for the western coal states. Table B-2 summarizes the values for midwestern and eastern states obtained from the seam analyses and reserve estimates. Table B-3 (which was not used for estimating purposes) summarizes the values for midwestern and eastern states obtained from mine analyses and capacity.

As can be seen, the number of mine analyses available is very low for some states, making a uniform basis for averaging by this method impossible. Furthermore the averages for states with few mines reporting (such as Illinois or Missouri) are quite different from the seam analyses. For these reasons, Tables B-1 and B-2 were used in subsequent calculations.

B-3. COAL USAGE BY REGION AND ORIGIN

In order to determine the sulfur emissions in coal-burning boilers, it is necessary to first estimate the consumption of coal by its origin in order to relate the average sulfur values determined above to the total coal consumed. A study by the Bureau of Mines has categorized coal consumption by regions of consumption and origin (Ref. B-5). This study considered utility consumption, coking operations, barge and train propulsion, and "other categories". Since most of the boilers considered in this study are smaller than utility size, coal-burning boiler distribution was assumed to be in accordance with the use distribution of coal in "other categories". In order to check this assumption, the percentage of the total coal burned by boilers of less than 63 kg/s (500×10^3 lb/hr) steam [given by Ehrenfeld (Ref. B-2)] for the Great Lakes and Central Regions was compared to the value resulting from the method described above. A value of 51.3% was obtained from Reference B-1 versus 54.5% calculated from the Bureau of Mines report. The slight disagreement could be due to the somewhat heavier concentration of industrial boilers in this region which would bias the sample toward the under 32 kg/s (250×10^3 lb/hr) steam range than if the 32 to 63 kg/s (250 to 500×10^3 lb/hr) steam units are included.

TABLE B-1. WESTERN COAL SULFUR CONTENT, HEATING VALUE, AND ASH FUSION TEMPERATURE (AVERAGED BY PRODUCTION)

State	Capacity*	1973 Production*	Sulfur†	AFT§	Heating Value#
Arizona	12.26	2.70	159	1466	25.3
Colorado	8.58	5.66	340	1529	31.1
Montana	23.49	9.03	296	1490	20.2
New Mexico	14.32	9.03	262	1589‡	22.8
North Dakota	11.14	8.48	645	1457	16.3
Utah	9.08	4.9	241	1475	30.5
Washington	11.19	2.91	342	1533	18.8
Wyoming	33.35	12.35	254	1482	23.5

*10^6 metric tons/year

†ng/J

§°K

#MJ/kg, as received

‡Navajo Mine not included

TABLE B-2. MIDWESTERN AND EASTERN COAL CHARACTERISTICS (AVERAGED BY SEAM RESERVES WHERE GIVEN)

State	Sulfur ng/J	Number of Seam Analyses
Alabama	434	67
Illinois	1272	61
Indiana	942	8
Kansas	1392	10
Kentucky (East)	[illegible]40	17
Kentucky (West)	1036	4
Maryland	658	11
Missouri	1350	6
Ohio	1127	16
Oklahoma	585	20
Pennsylvania	632	43
Tennessee	645	44
Virginia	292	45
West Virginia	378	27

TABLE B-3. MIDWESTERN AND EASTERN COAL CHARACTERISTICS FROM MINE DATA (WEIGHTED BY PRODUCTION)

State	Sulfur ng/J	No. of Mines Reporting
Alabama	211	5
Illinois	778	4
Indiana	1170	1
Kentucky	439	40
Maryland	619	3
Missouri	2391	1
Ohio	1729	14
Oklahoma	185	1
Pennsylvania	727	39
Virginia	348	4
West Virginia	464	39

Table B-4 summarizes the data for coal consumption according to the region of origin and the state of use. These data were converted to percentages to estimate the regional distribution of the total boiler heat (coal) consumption. The regions of origin and average sulfur content (derived by averaging state averages of Tables B-1 and B-2) are delineated in Table B-5.

B.4 ESTIMATE MAXIMUM POSSIBLE SULFUR REDUCTION

B.4.1 Present Sulfur Emissions

The data of Tables B-2 through B-5 were applied to calculate the sulfur emissions from coal-burning boilers in the 1.3 to 32 kg/s (10,000 to 250,000 lb/hr) steam range. The sulfur emitted was simply:

$$M_{s_{1.3-12.6}} = \sum_{1}^{23} f_i \, s_i \, Q_{22-221}$$

$$M_{s_{12.7-32}} = \sum_{1}^{23} f_i \, s_i \, Q_{221-551}$$

where

$M_{s_{1.3-12.6}}$ = mass of sulfur (as sulfur) emitted from boilers in the 1.3 to 12.6 kg/s range

f_i = fraction of the coal originating in region i

s_i = average sulfur content of coal in region i

$M_{s_{12.7-32}}$ = mass of sulfur (as sulfur) emitted from boilers in the 12.7 to 32 kg/s

Substitution of the appropriate values gives:

$$M_{s_{1.3-12.6}} = 7.31 \times 10^5 \text{ metric tons/year (as sulfur)}$$

$$M_{s_{12.7-32}} = 1.019 \times 10^6 \text{ metric tons/year (as sulfur)}$$

When the same data was used to estimate the sulfur emissions only in the midwestern (CU) and Great Lakes (GL) states, the following values were obtained:

$$M_{s_{1.3-12.6}}(\text{CU,GL}) = 4.194 \times 10^5 \text{ metric tons/year}$$

$$M_{s_{12.7-32}}(\text{CU,GL}) = 5.855 \times 10^5 \text{ metric tons/year}$$

TABLE B-4. COAL USAGE FOR "OTHER DEVICES" BY REGION OF ORIGIN AND STATE OF USE (1973) (Thousands of Metric Tons/Year)

Region of Origin	1	2	3&6	4	5	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	Total
STATE OF USE																							
Massachusetts	4		43				8																55
Connecticut	38						6																44
Maine, N.H., Vt, R.I.	8	1	9				10																28
New York	917	276	724	84			131																2,144
New Jersey				3		1	67																71
Pennsylvania	1400	2083	728	92		86	760																5,149
Ohio	47	277	131	4459			3622															2	8,484
Indiana	3			3		15	260	159	580	3748													4,768
Illinois			8			8	571	101	3104	91													3,868
Michigan			120	885		264	3333	363	360	66												27	5,405
Minnesota			20	3		2	231	10	96	239							2				345	853	1,768
Wisconsin	91		55	51		34	1265	230	585	82							109					6	2,433
Iowa						48	11	174	1043	--	34			13				1					1,324
Missouri							5	11	1241					25		12							1,293
N. Dak., S. Dak.																		6		285			291
Neb., Kansas													5	121		45		240					411
Del., Maryland	700		12			56	73																840
Wash. DC	21		42				172																235
Virginia	6					156	2122																2,284
W. Virginia	11	408	997	434		175	1937																3,962
N. Carolina			15			5	1287																1,307
S. Carolina							1004																1,004
Georgia, Florida							182		91	91	91												454
Kentucky			28			23	674	971															1,696
Tennessee						27	1324	418		91		151											2,011
Ala., Miss.						38	5	1652	289			1514											3,498
Ark, La, Ok, Texas							68					49		1927									2,044
Colorado						9							94		91	284		318					796
Utah																		39	655				684
Mont., Idaho																		131	122			15	268
Wyoming																		223					223
New Mexico													12				4						16
Ariz., Nevada																	23		114				124
Wash., Oregon																		75	103			27	211
																							59,157

TABLE B-5. AVERAGE SULFUR CONTENT BY COAL-PRODUCING REGIONS (1973)

Region	States Where Used	Sulfur ng/J(lb/MBtu)	% of Total Coal ng/J(lb/MBtu)
1	E. Penn., Md	632 (1.47)	2261 (5.49)
2	W. Penn.	632 (1.47)	2215 (5.15)
3 & 6	W. Virginia	378 (0.88)	2133 (4.96)
4	Ohio	1127 (2.62)	4442 (10.33)
5	Michigan	— —	— —
7	W. Virginia	378 (0.88)	688 (1.60)
8	W. Va., E. Ky., Tenn.	456 (1.06)	13,756 (31.99)
9	W. Kentucky	1036 (2.41)	2971 (6.91)
10	Illinois	1277 (2.97)	5371 (12.49)
11	Indiana	942 (2.19)	3152 (7.33)
12	Iowa	— —	— —
13	Ala., Ga., Tenn.	542 (1.26)	1247 (2.90)
14	Ark., Okla.	585 (1.36)	82 (0.19)
15	Ky., Tenn., Mo., Okla.	903 (2.10)	1514 (3.52)
16	Colorado	340 (0.79)	65 (0.15)
17	Colorado, N. Mex.	301 (0.70)	250 (0.58)
18	N. Mex., Arizona	211 (0.49)	99 (0.23)
19	Wyoming	254 (0.59)	744 (1.73)
20	Utah	241 (0.56)	718 (1.67)
21	N. Dak., S. Dak.	645 (1.50)	206 (0.48)
22	Montana	396 (0.92)	245 (0.57)
23	Wash., Oregon	344 (0.80)	662 (1.54)

It is significant that the total emissions from this district (which is most accessible to western coal sources) are 57% of the national total. This is because of the high concentration of boilers in this region and the high sulfur content of the coal burned in these regions.

B.4.2 Reduction in Sulfur by Using Western Coal

The sulfur emissions using western coal were estimated both nationwide and for the midwestern-Great Lakes region for two different cases:

1. Western coal characteristics were weighted according to present mine capacity. That is, increases in production would be met by increases in all mines proportional to their present capacity.
2. Western coal characteristics of individual states were used.

Table B-6 summarizes the nationwide sulfur emissions and net savings realized by using western coal for the boilers in the 1.3 to 32 kg/s range.

TABLE B-6. NATIONWIDE SULFUR EMISSIONS USING WESTERN COAL

Coal Source	Total Sulfur Emitted*	Net Decrease*	% Decrease
Composite western	7.7	9.8	56
Arizona	3.8	13.71	78
Wyoming	6.08	11.35	65
Montana	9.53	7.988	46

*10^5 metric tons/yr as sulfur

Table B-7 summarizes the sulfur emissions and reduction possible for the midwestern-Great Lakes region for the same conditions.

TABLE B-7. MIDWESTERN-GREAT LAKES SULFUR EMISSIONS USING WESTERN COAL

Coal Source	Total Sulfur Emitted*	Net Decrease*	Percent Decrease
Composite western	3.813	6.264	62
Arizona	1.906	8.17	81
Wyoming	2.996	6.99	70
Montana	4.721	5.356	53

*10^5 metric tons/yr as sulfur

In both cases, sizable reductions are seen to be possible. The midwestern-Great Lakes region has the potential for even larger reductions than the nationwide average because of the higher sulfur fuels currently being burned in this region.

These reductions are theoretical reductions and do not reflect any problems that may occur while firing western coal. Potential problems such as requipment derating or an increase in other emissions would adversely impact these projections. On the positive side, an additional reduction may be realized in SO_x stack emissions due to differing sulfur forms (organic, pyritic, or sulfates) in western coals as compared to midwestern or eastern coals. Also, the different nature of the western coal ash (high CaO, NaO, and MgO) may act to effectively reduce SO_x emissions.

REFERENCES FOR APPENDIX B

B-1 Locklin, D. W., et al., "Design Trends and Operating Problems in Combustion Modification of Industrial Boilers," EPA 650/2-74-032, April 1974.

B-2 Ehrenfeld, J. R., et al., "Systematic Study of Air Pollution from Intermediate Size Fossil-Fuel Combustion Equipment," Final Report, Contract CPA 22-69-85, Walden Research Corporation, July 1971.

B-3 Neilson, G. J., ed., 1974 Keystone Coal Industry Manual, McGraw-Hill, New York, 1974.

B-4 Ctvrtnicek, J. E., et al., "Evaluation of Low-Sulfur Western Coal Characteristics, Utilization, and Combustion Experience," EPA 650/2-75-046, May 1975.

B-5 Bituminous Coal and Lignite Distribution - Calendar Year 1973, Mineral Industries Surveys, U.S. Dept. of the Interior, Bureau of Mines, Washington, D.C., April 12, 1974.

APPENDIX C

DETAILED COMBUSTION REQUIREMENTS FOR SPECIFIC BOILER FIRING TYPES

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C.1 INTRODUCTION

Coal firing of industrial boilers can be separated into two broad classes--suspension firing and grate firing.

Suspension firing is normally applied in larger size units; however, units as small as 4.4 kg/s (35,000 lb/hr) steam have been built for pulverized coal firing. Current economics would indicate a break-even point in the 25.2 to 32 kg/s (200,000 to 250,000 lb/hr) steam flow range. Suspension firing includes both pulverized coal firing in which the coal is crushed to less than 6.4 mm (1/4 in.) size which produces about 10% through a 200-mesh screen.

Grate firing comprises three general stoker types: underfed, overfed, and spreaders with a number of variations in feed methods and grate designs. Stoker-fired units have been built covering the entire capacity range of this study.

Considering the number of stoker manufacturers and the number of boiler companies serving the industrial boiler market and the changes in design philosophy which have taken place over the years since stokers were first introduced around 1900, the present stoker-fired boiler population represents a highly individualized array of equipment.

A similar situation exists regarding pulverized coal-fired boilers. Since their commercial inception in 1920, many changes in furnace shape, burner design, amount of furnace water cooling, method of ash removal, and heat release rate have evolved, so that each unit is highly individualized and tailored to the expected coal characteristics and plant requirements.

Generalization will be made in this study which can be directly applied to certain units; undoubtedly other units can be found which will not conform to these generalizations by reason of furnace design, firing system characteristics or fuel preparation.

The principal methods for firing coal in industrial boilers are categorized in Table C-1, along with salient features which describe their application. Fuel requirements are outlined in Table C-2.

C.2 UNDERFED STOKERS

C.2.1 Single Retort Stokers

Single retort stokers, as illustrated in Figure C-1, are the earliest type of underfed stokers. Coal is fed to the bottom portion of the fuel bed either in small increments by a power-driven ram or continuously by a screw conveyor. Moisture and volatile matter are driven off in the lower part of the fuel bed and the coal is coked in an oxidizing atmosphere. The hydrocarbons burn in an air-rich atmosphere and pass upward through the hot incandescent fuel bed, thus lessening the tendency for smoke formation. The coked coal is forced upward into the active fuel bed and spills over onto side grates where combustion is completed. Dead-plates at the stoker sides are provided for collecting ash and refuse.

While the earliest patents date from 1838, intensive development of this stoker occurred between 1889 and 1906. Important improvements were reciprocating retort bottom with auxiliary feed rams to distribute the coal from front to rear; moving grate bars to break up coke formations and distribute coal laterally across the grate; hollow, air-cooled grate bars; and side dumping grates for discharging ash. These features are incorporated into the majority of single retort underfed stokers in service or on the market today.

A number of distinctive designs are manufactured ranging from 0.93 to 11.7 m^2 (10 to 126 ft^2) of grate area. These stokers are generally considered applicable up to 4.4 kg/s (35,000 lb/hr) steam.

Fuels ranging from lignite to anthracite are successfully burned; however, single-retort underfed stokers are principally used for burning eastern coking bituminous coals and those midwestern free-burning coals with sufficiently high ash softening temperatures [1589 °K (2400 °F) or greater] to avoid clinkering in the relatively thick fuel beds. The preferred sizing of bituminous coal is 2.54 cm to 3.81 cm (1 to 1-1/2 in.)

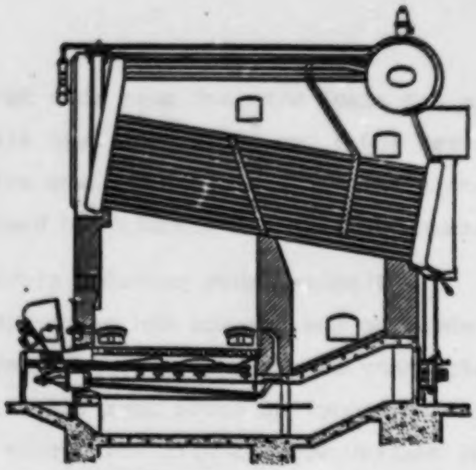
TABLE C-1. COAL FIRING METHODS FOR INDUSTRIAL BOILERS

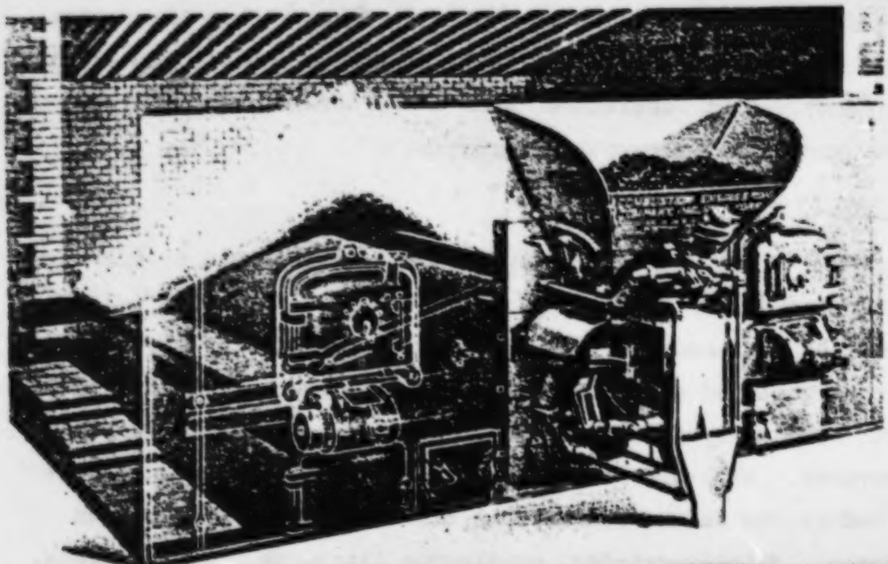
Firing Method	Grate Area Size Range, m^2 (ft^2)	Grate, MW/m^2 ($Btu/ft^2\text{-}hr$)	Furnace Construction	Max. Furnace Heat Release MJ/m^3 (Btu/ft^3)	Boiler Capacity Range, kg/s (lb/hr)	Load Response
1. Underfed Stoker						
Single Retort						
Stationary Grate	0.9-4.5 (10-48)	0.79 (250,000)	Refractory	1676 (45,000)	1.2-6.1 (2,000-10,000)	Poor ↓
Reciprocating Grate	1.4-4.6 (15-50)	1.10 (350,000)	Refractory	1676 (45,000)	1.2-9.2 (2,000-15,000)	
Reciprocating Grate	3.3-11.6 (36-125)	1.34 (425,000)	Water Cooled	2235 (60,000)	1.2-28 (10,000-45,000)	
Multiple Retort	3.3-47 (35-500)	1.89 (600,000)	Partial to Full W.C.	1304 (35,000)	12-184 (20,000-300,000	
2. Overfed Stoker						
Chain Grate	4.6-65 (50-700)	1.58 (500,000)	Partial to Full W.C.	1118 (30,000)	15-153 (25,000-250,000)	Fair ↓
Traveling Grate	4.6-65 (50-700)	1.58 (500,000)	Partial to Full W.C.	1118 (30,000)	15-153 (25,000-250,000)	
Vibrating Grate	1.4-23 (15-250)	1.26 (400,000)	Partial to Full W.C.	1118 (30,000)	6-61 (6,000-100,000)	
3. Spreader Stoker						
Stationary Grate	2.6-8.4 (28-90)	1.42 (450,000)	Refr to Partial W.C.	1118 (30,000)	3-24 (5,000-40,000)	Good ↓
Dumping Grate	2.6-15.8 (28-170)	1.42 (450,000)	Refr to Partial W.C.	1118 (30,000)	3-46 (5,000-75,000)	
Traveling Grate	9.3-44.6 (100-480)	2.36 (750,000)	Partial to Full W.C.	1118 (30,000)	46-214 (75,000-350,000)	
Vibrating Grate	4.6-13.9 (50-150)	1.89 (600,000)	Partial to Full W.C.	1118 (30,000)	3-46 (5,000-75,000)	
Oscillating Grate	27.9 (300)	1.89 (600,000)			92 (150,000)	
4. Pulverized Coal	---	---	Water Cooled	N/A	21 (35,000) up	Excellent ↓
5. Cyclone Furnace	---	---	Water Cooled	N/A	52 (85,000) up	

TABLE C-2. FUEL REQUIREMENTS FOR VARIOUS FIRING METHODS.

	Firing Type	Coal Type[g]	Sizing	Ash, %	AST, °K (°F)	Notes
Underfed	Single Retort	Coking and caking Free burning	2.54 to 3.81 cm (1" to 1-1/2") nut and slack (<50% through 6.4 cm (1/4") screen)	<10%	1589(2400)[a]	(a) Reduced burning rate for lower ash softening temperatures. (b) Reduce fuel rate 12% with free burning coal in open furnace. Long rear arch improves combustion in free burning coal. (c) Lower fusion temperature ash can be accommodated at lower burning rates. (d) Preheated air temp. up to 450°K(350°F) can generally be used with stoker firing without excessive maintenance. (e) Preheated air temp. for pulverized coal drying ranges from 450°K (350°F) to 672°K (750°F) depending on moisture (f) Fuel to be delivered across the width of the stoker hopper without size segregation. (g) Excluding anthracite.
	Multiple Retort	Free burning coal Tends to drift[b,f]	5.08 cm (2") nut and slack (<50% through 6.4 cm (1/4") screen)	<10%	1589 (2400)	
Overfed	Chain Grate	All except caking bituminous[f]	2.54 cm (1") nut and slack	<6% on dry basis	1422 (2100)[c]	
	Traveling Grate	All except caking bituminous[f]	2.54 cm (1") nut and slack - will handle fine coal	<6% on dry basis	1422 (2100)[c]	
	Vibrating Grate	All types[f]	2.54 cm (1") nut and slack - less fines preferred	<6% on dry basis	(<1422)(<2100)	
Spreader Stokers	Stationary Grate	All types	1.91 cm(3/4") nut and slack	---	---	
	Dumping Grate	All types	1.91 cm(3/4") nut and slack	---	---	
	Traveling Grate	All types	1.91 cm(3/4") nut and slack	---	---	
	Vibrating Grate	All types	1.91 cm(3/4") nut and slack - less fines preferred	---	---	
	Pulverized Coal	All types	1.91 cm(3/4") nut and slack	---	---	
	Cyclone	All types subject to ash properties	Crushed to 95% thru 4-mesh screen	6 - 25%	slag viscosity criteria	

Single Retort Stoker for a Cross-Drum Straight-Tube Boiler.





View with part of the front and fuel bed in phantom to show interior and fire on rear part of grate (Ref. C-1).

Cross-section showing air distribution system (Ref. C-1).

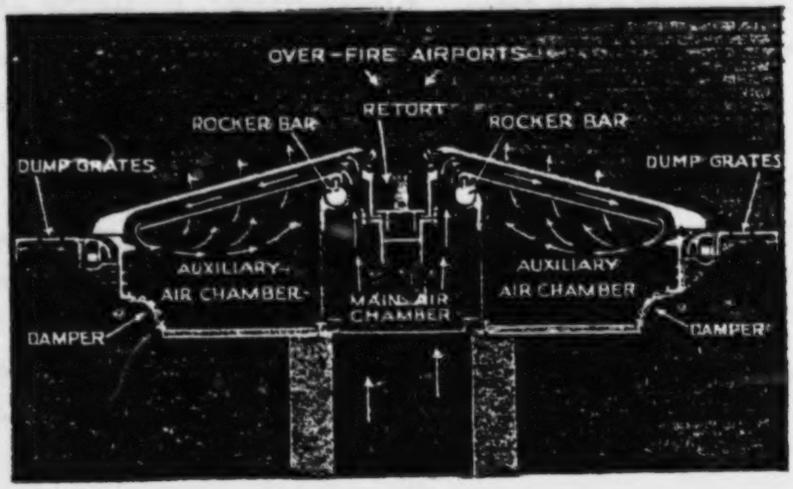

OVER-FIRE AIRPORTS
RETORT
ROCKER BAR
ROCKER BAR
DUMP GRATES
DUMP GRATES
AUXILIARY AIR CHAMBER
MAIN AIR CHAMBER
AUXILIARY AIR CHAMBER
DAMPER
DAMPER

Figure C-1. Single retort stoker.

nut and slack with not more than 50% passing a 6.4 cm (1/4") round hole screen and a top individual lump size not larger than 3.18 cm (1-1/4"). Easily friable coals can be used with larger lump size because of the degradation occurring in transit and handling.

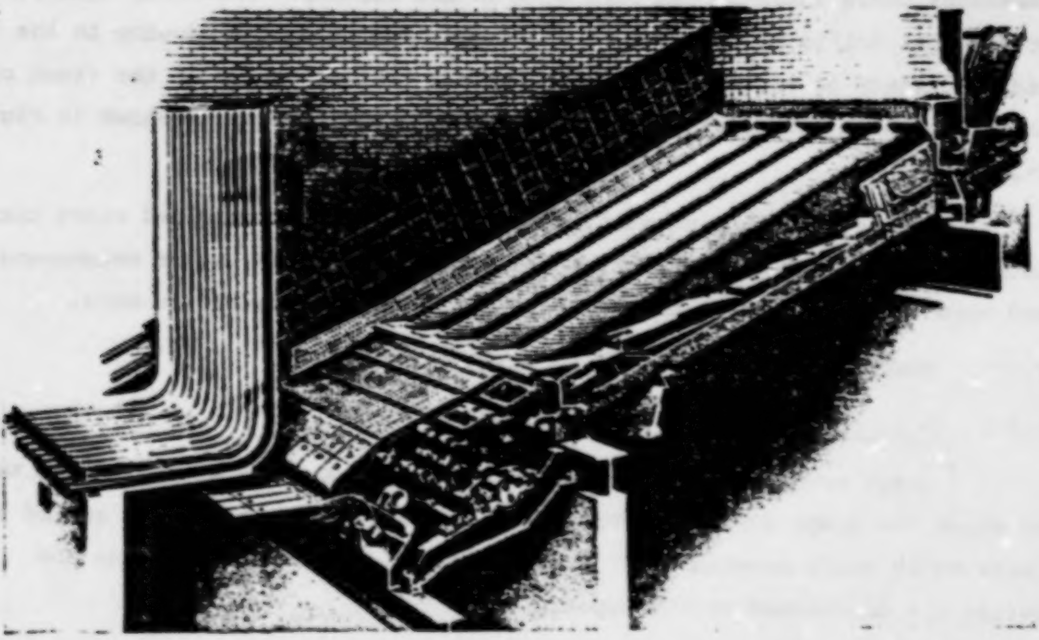
Single-retort underfed stokers do not require ignition or combustion arches, so the furnace can be constructed with simple vertical walls either refractory or water cooled. Combustion rate in terms of W/m^2 (Btu per square foot per hour) of grate area range from $1.1x10^6$ W/m^2 (350,000 $Btu/ft^2 \cdot hr$) for the smaller stokers with refractory furnaces up to $1.34x10^6$ W/m^2 (425,000 $Btu/ft^2 \cdot hr$) for the larger stokers in water-cooled furnaces. Heat liberation rates up to $4.7x10^5$ W/m^3 (45,000 $Btu/ft^3 \cdot hr$) of furnace volume are acceptable for refractory furnaces. Heat liberation rates up to $6.2x10^5$ W/m^3 (60,000 $Btu/ft^3 \cdot hr$) can be used with water-cooled furnaces.

C.2.2 Multiple Retort Stokers

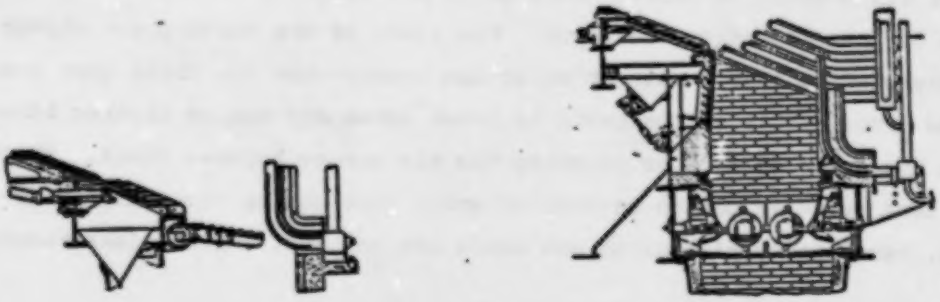
Multiple retort stokers were developed shortly after 1900 to fulfill a need for larger stokers. This type, as illustrated in Figure C-2, consists of a series of inclined retorts with tuyeres between for air admission. Each retort is equipped with a primary ram which feeds coal at the head of the retort. Secondary pushers slowly move the coal to the rear and upward over the tuyeres. An overfeed section is located at the rear to complete combustion before the refuse reaches the discharge section which can be one of three types: clinker-grinder, continuous discharge, or dump grate.

Application of rearwall and sidewall water cooling enabled successful operation in capacities up to 38 kg/s (300,000 lb/hr) steam. Furnaces are generally sized to limit heat liberation rates to $3.6x10^5$ W/m^3 (35,000 $Btu/ft^3 \cdot hr$).

The multiple retort underfed stoker works best on crushed coal with a maximum size of 5.1 cm (2 in.) with not more than 50% through a 6.4 cm (1/4") round hole screen, a volatile content between 20% and 30%, ash content of 6% to 8%, and an ash softening temperature above 1589°K (2400 °F). The ash should not contain more than 15% Fe_2O_3. The coal sizing should be uniform across the width of the stoker hopper.



Multiple-Retort Stoker Showing Details of Components (Ref. C-2)



Ash Discharge Arrangement Showing Single-Dump Type of Construction

Ash Discharge Arrangement of Air-Admitting Fire Bars, Protecting Wall Blocks, Breaker Plates, and Double-Roll Clinker Grinders

Figure C-2. Multiple retort stoker.

Control of the stoker fuel bed has been difficult with non-agglomerating (western) coals which do not form coke in the furnace. Partially ignited fuel or raw coal drifts to the rear of the stoker and blowholes develop in the fuel bed. Ignition is improved and drifting coal is redeposited at the front of the stoker if a long rear arch is installed in the furnace as shown in Figure C-3.

The installation of multiple retort stokers has declined since the introduction of spreader stokers because of higher cost, higher maintenance, and more difficult operation associated with multiple retort stokers.

C.3 OVERFED STOKERS

C.3.1 Chain or Traveling Grate Stokers

Chain or traveling grate stokers can be described as endless belts in which the grate surface is the belt. Fuel is deposited on one end of the grate which moves continuously toward the rear of the furnace. Ash and refuse are discharged at the opposite end.

The grate surface of a chain grate stoker consists of a series of cast-iron or steel links connected by bars to form an endless chain. In the traveling grate or bar-and-key design, a series of cast-iron sections or keys are mounted on carrier bars which are fastened to two or more drive chains to form an endless conveyor. The links of the chain grate stoker are assembled so that a scissoring action occurs when the chain goes over the end drums. This action tends to break loose any ash or clinker adhering to the grate surface or plugging the air spaces between links. There is no such relative motion between adjacent keys on the traveling grate design, hence badly clinkering ash coals are not well suited (see Figure C-4).

Natural draft chain-grate stokers were developed in the latter half of the 19th Century and offered commercially in 1896. Traveling grate stokers were introduced commercially in 1893. Natural draft stokers have a free air space through the grate of 18% to 22% and operate with a draft loss through the fuel bed of 2.54 mm to 12.7 mm (0.1 to 0.5 in.) of water. A coarse coal with few fines is preferred.

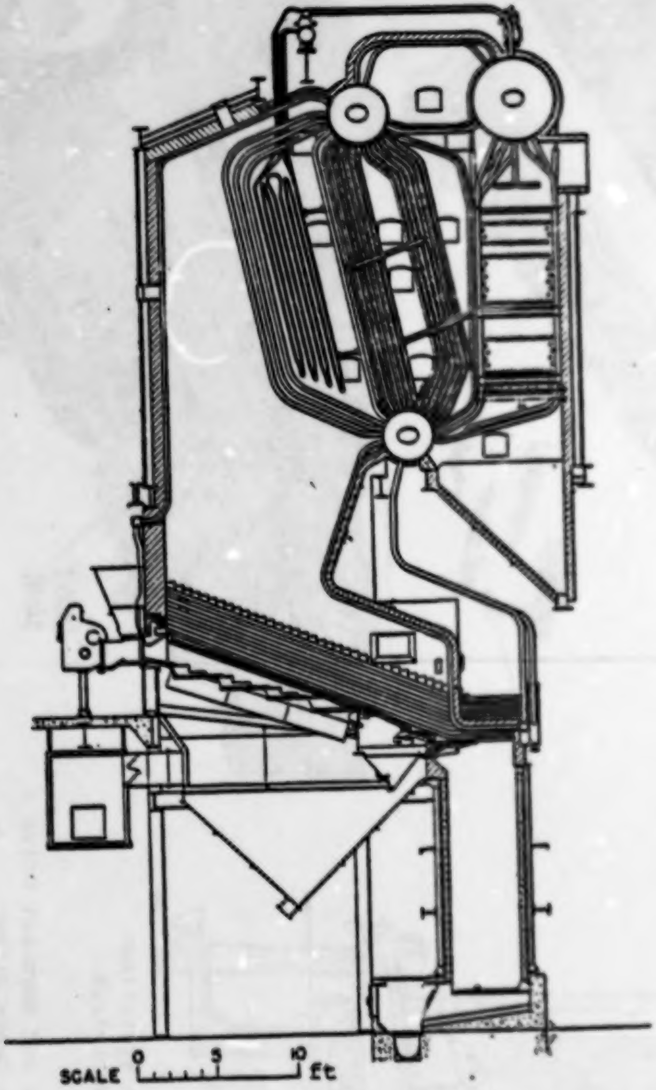
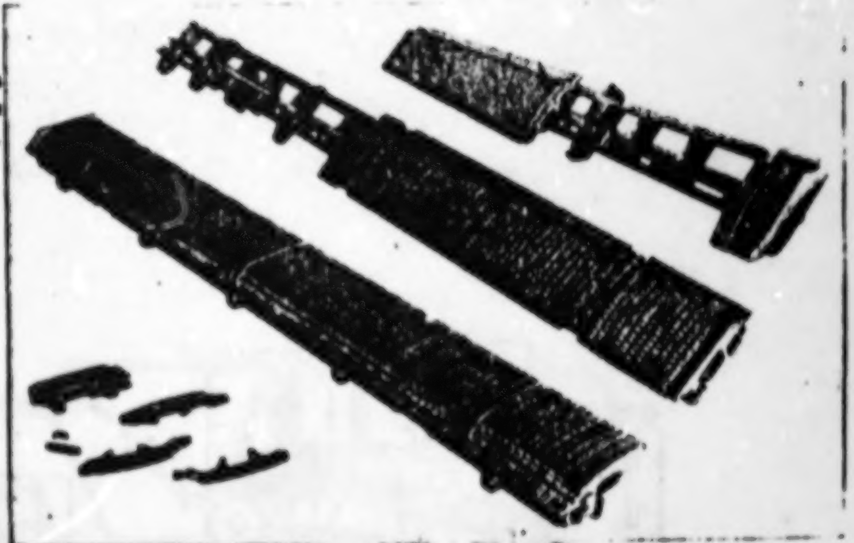
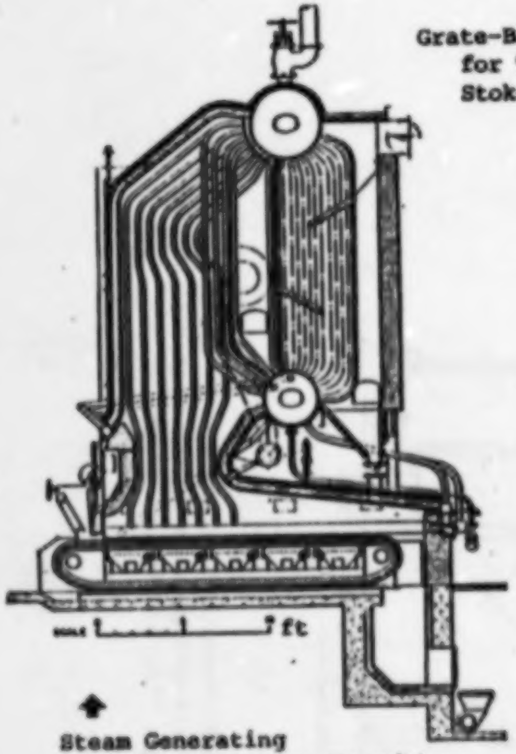


Figure C-3. Three-drum steam generating unit fired by a continuous-discharge multiple-retort stoker with rear-arch furnace. Capacity 24 kg/s (150,000 lb/hr) steam.

Grate-Bar Construction
for Traveling Grate
Stokers (Ref. C-1).





Steam Generating
Unit Equipped with Traveling-
Grate Stoker and Rear-Arch
Furnace.

Chain and Sprocket Drive -
Chain Grate Stoker
(Ref. C-2).

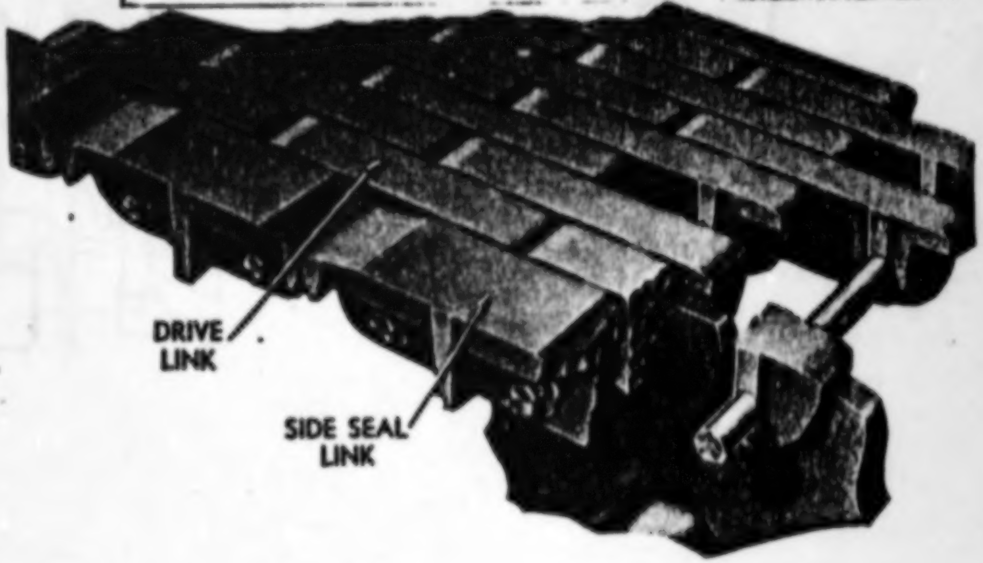

DRIVE LINK
SIDE SEAL LINK

Figure C-4. Chain or traveling grate stoker.

Forced draft stokers, introduced in the 1920's to meet the demand for higher capacity and better performance, have generally made the natural draft design obsolete. Forced draft stokers have a free air space through the grate of 6% to 10% and consequently can burn finer coal. Normally, draft loss through the fuel bed is 2.54 to 5.08 cm (1 to 2 in.). These stokers are suitable for boiler sizes from 3 to 31 kg/s (25,000 to 250,000 lb/hr) steam.

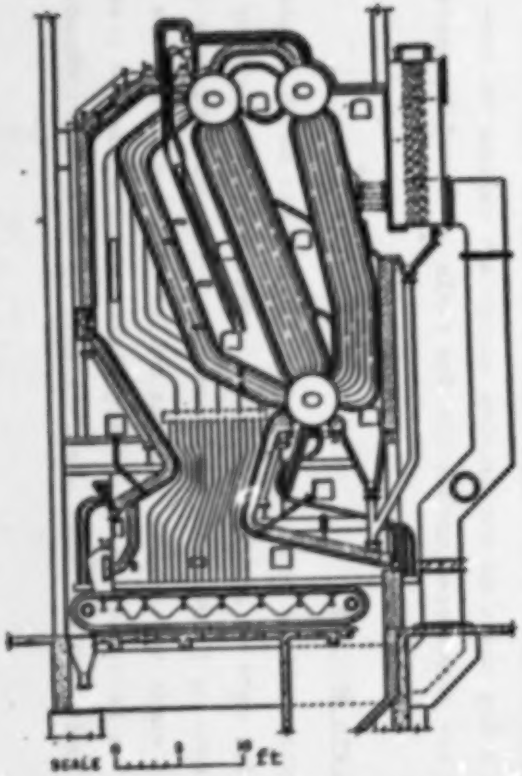
A wide variety of coals can be burned on chain and traveling grate stokers. The notable exception is highly coking bituminous coal which tends to mat and prevent air from passing through the fuel bed.

A great deal of experimentation has been done on furnace design to provide satisfactory ignition and eliminate stratification resulting in unburned gases or carbon carry-over. Initially front, rear, or combinations of front and rear arches were relied on to promote ignition and mixing. More recently, high-velocity air jets have replaced front arches to provide turbulence for completing combustion of distilled volatile matter (see Figure C-5). Long rear arches are still considered effective in promoting burnout and transporting incandescent particles to the front of the stoker.

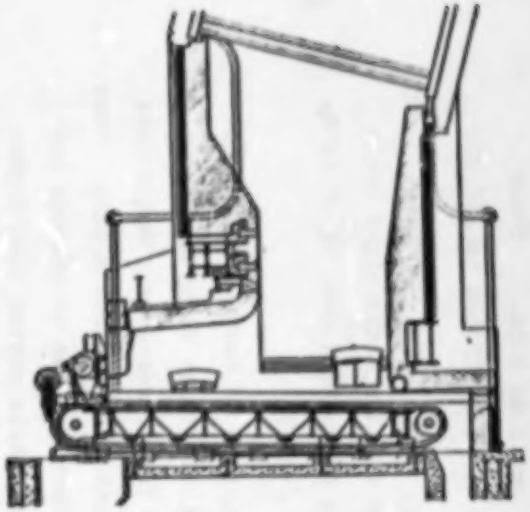
Maximum continuous burning rates for bituminous coals range from 1.34 to 15.8×10^6 W/m^2 (425,000 to 500,000 Btu/ft^2·hr). The lower burning rate applies to high moisture (>20%), high ash (>20%) coals. Coals with less than 8% ash on a dry basis do not provide enough ash residue to protect the grates and are considered unsuitable for chain or traveling grate stokers.

C.3.2 Vibrating Grate Stokers

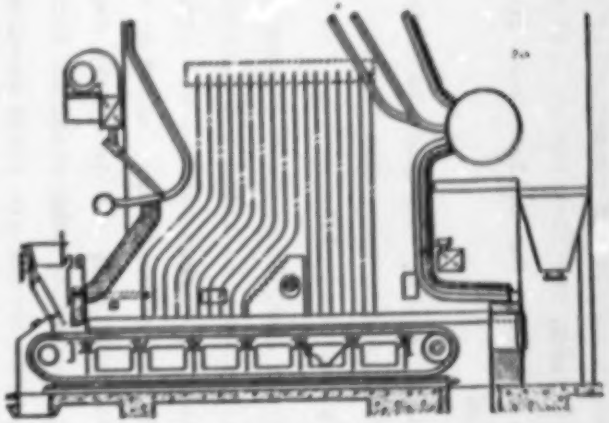
Vibrating grate stokers are a more recent development in which coal from the hopper is fed onto an inclined grate and moved over the grate by intermittent vibrations as illustrated in Figure C-6. The grate surface is mounted on a grid of water tubes tied into the boiler circulation and the entire grate structure is supported by flexing plates which allow the grate to be vibrated as a unit. These units are available up to a boiler capacity



Steam Generating Unit with Overfire Air and Combination-Arch Furnace. Capacity 10 kg/s (80,000 lb/hr) steam.



An Early Front-Arch Type of Furnace for Free-Burning Bituminous Coals.



An Open-Type Furnace for Bituminous Coals.

Figure C-5. Chain or traveling grate stoker with high-velocity air jets.

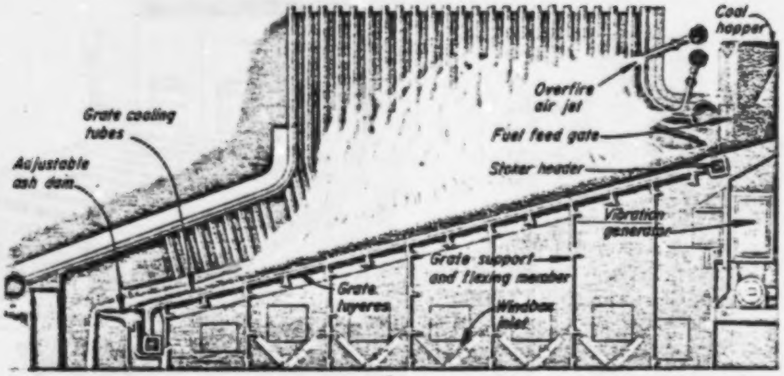

Coal hopper
Overfire air jet
Fuel feed gate
Stoker header
Grate cooling tubes
Adjustable ash dam
Vibration generator
Grate support and flexing member
Grate tuyeres
Windbox inlet

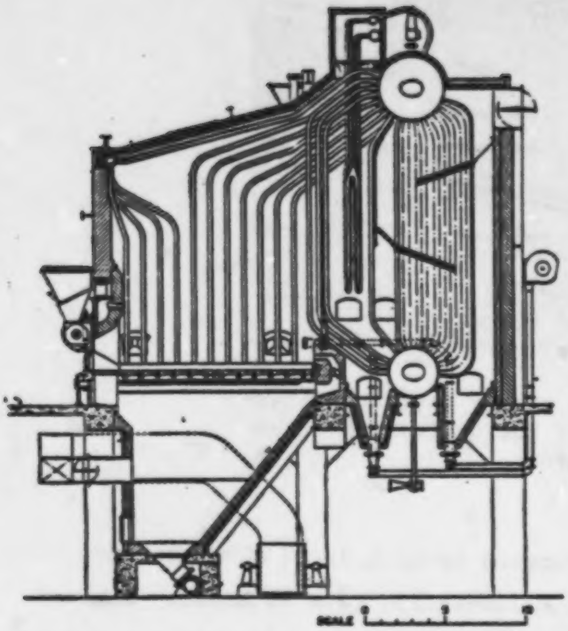
Figure C-6. Vibrating-grate-type stoker combines water-cooling protection of the grate with intermittent grate vibration.

of 12.6 kg/s (100,000 lb/hr) and can be operated up to $1.3\text{x}10^6$ W/m^2 (400,000 Btu/ft^2·hr) of grate surface per hour. Heat liberation rate is usually limited to $3.1\text{x}10^5$ W/m^3(30,000 Btu/ft^3·hr) of furnace volume per hour. Overfire air jets are used to provide turbulence for burnout of volatile matter. The vibra-grate stoker will operate successfully with caking coals but an excessive amount of fines will create problems with fine coal or ash sifting through the grate.

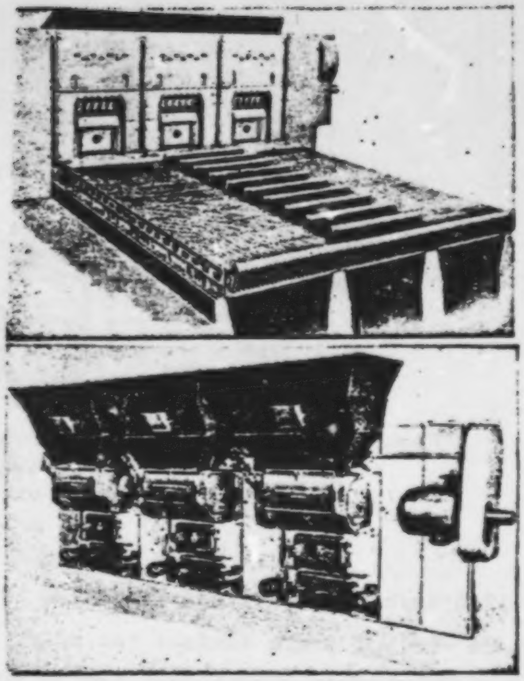
C.3.3 Spreader Stokers

The modern spreader stoker, illustrated in Figure C-7, consists of one or more feeder units mounted on the boiler front, each comprising a coal hopper, a feeder that regulates the flow of coal, and a distributor rotor that throws the coal into the furnace and distributes it on the grate. The stoker grates may be of the stationary, dumping, or continuous discharge type.

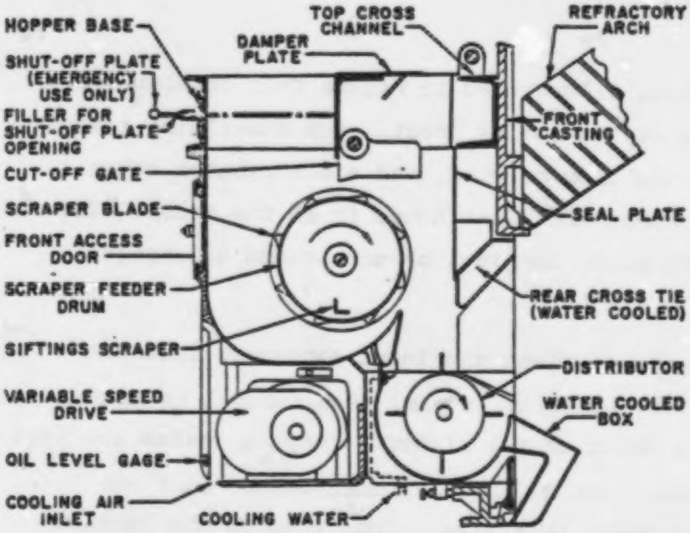
The stationary grate is the simplest and least expensive form and is suitable up to about 5 kg/s (40,000 lb/hr) steam. Ash removal is manual through grate-level doors at the front of the stoker. Dumping grates are used up to 9 kg/s (75,000 lb/hr) steam. Grates are sectionalized so that one portion of the fuel bed may be cleaned at a time. Coal feed to the section



Dumping-Grate Spreader-Stoker-Fired Unit Having a Capacity of 5 kg/s (39,000 lb/hr) steam.



Views of Dumping-Grate Spreader Stoker showing arrangement of feeder units. Grates are shown in both the operating and dumping positions (Ref. C-1).


HOPPER BASE
SHUT-OFF PLATE (EMERGENCY USE ONLY)
FILLER FOR SHUT-OFF PLATE OPENING
CUT-OFF GATE
SCRAPER BLADE
FRONT ACCESS DOOR
SCRAPER FEEDER DRUM
SIFTINGS SCRAPER
VARIABLE SPEED DRIVE
OIL LEVEL GAGE
COOLING AIR INLET
COOLING WATER
TOP CROSS CHANNEL
DAMPER PLATE
REFRACTORY ARCH
FRONT CASTING
SEAL PLATE
REAR CROSS TIE (WATER COOLED)
DISTRIBUTOR
WATER COOLED BOX

Feeder for Spreader Stoker

Figure C-7. Spreader stokers.

is stopped during the cleaning operation. For units from 9.9 to 38 kg/s (75,000 to 300,000 lb/hr) steam, a traveling grate is used for continuous ash discharge. The usual direction of travel is from rear to front as illustrated in Figure C-8, although travel in the opposite direction can also be used. Vibrating or oscillating grates have also been used with the spreader stokers.

The spreader stoker can burn a wider range of fuels than any other stoker type. This method of firing was developed primarily to burn the lower grades of coal with high ash content and low ash fusion temperature. Caking qualities of coals have little effect on performance.

As with other stoker types, mechanical spreader firing dates from the 1800's. However, the spreader stoker did not become widely accepted until the 1930's following the introduction of more efficient feeding and distributing mechanisms and high-resistance forced-draft grate surfaces. The spreader stoker now ranks high in industrial applications burning solid fuels with respect to efficiency, operational flexibility, maintenance, capacity, and ability to burn a wide range of fuels.

When used with stationary or dumping grates, heat release rates are limited to 1.4×10^6 W/m^2 (450,000 Btu/ft^2·hr) of grate. With continuous discharge grates, heat release rates up to 2.4×10^6 W/m^2 (750,000 Btu/ft^2·hr) are possible. The furnace heat release rate is generally limited to 3.1×10^5 W/m^3 (30,000 Btu/ft^3·hr) of furnace volume because of the greater amount of suspension firing. Vertical furnace walls are preferred with overfire air jets providing turbulence for mixing and combustible burnout.

The fuel should be sized to pass a 1.91 cm (3/4") screen with considerable range in particle size to produce a uniform fuel bed. If the particles are all of one size, much of the fuel will fall on one portion of the grate. Larger lumps tend to increase ashpit losses. When the coal is too coarse with a large proportion above 0.54 cm (1/4"), the fuel bed may not burn down evenly and clinkers may tend to form in the areas containing the larger sizes.

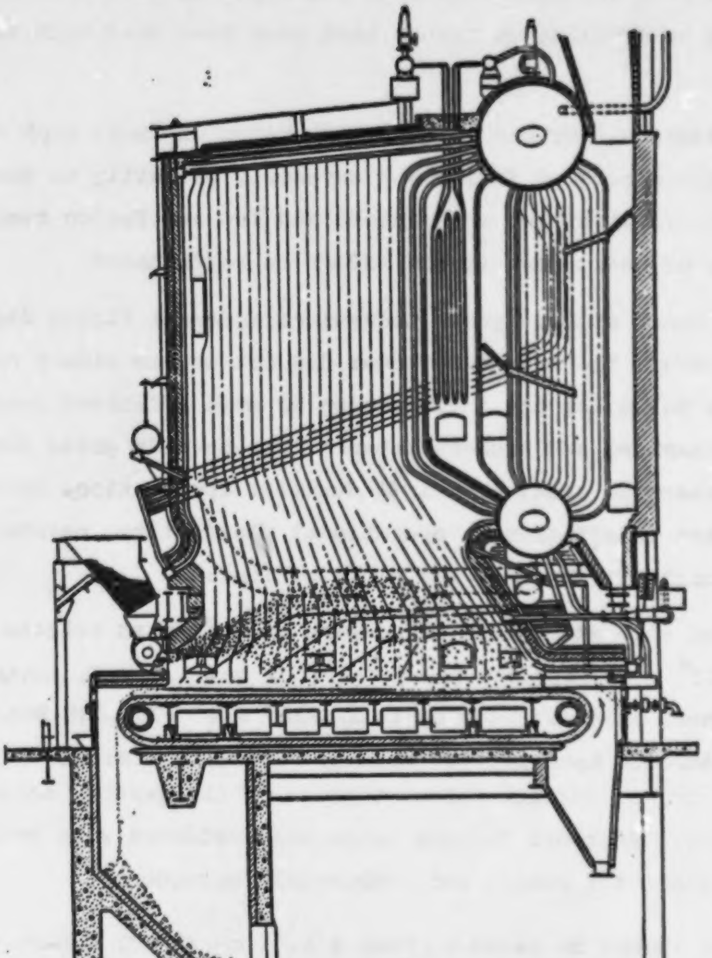

SCALE
0
5
10
ft
12.7
25.4 cm

Figure C-8. Steam generating unit equipped with continuous-discharge type of spreader stoker. Capacity 19 kg/s (150,000 lb/hr) steam.

C.3.4 Pulverized Coal Firing

The application of pulverized coal firing to steam-generating units began around 1920. There has been a progressive increase in its use for power and process steam generation in preference to stoker firing. Much larger units are possible than with stoker firing, labor costs are lower, and operating flexibility is greater.

Although it would be technically possible to design small units for pulverized coal firing, stoker units are presently considered more economical below 25 kg/s (200,000 lb/hr) steam.

Pulverizer capacity is one of the most important considerations in designing a pulverized-coal-fired unit. Four functions are normally provided by the pulverizer system: pulverizing, drying, classifying to required fineness, and transporting the coal to the burners in an air stream. The system capacity is dependent upon coal properties such as moisture content, grindability, and burning characteristics. If sufficient heat is not available in the preheated air to evaporate the surface moisture in the fuel, the drying operation will limit mill output rather than the grinding capacity. High volatile coals ignite more readily than low volatile coals and consequently need less fine pulverization. Typically, with high volatile coals, 70% through 200-mesh screen is considered adequate. The percentage greater than 50-mesh should be limited to 2% to reduce slagging tendencies and carbon loss.

Three general types of pulverizers are available:

1. Low speed, ball or tube mills which tumble coal and 2.54 cm (1") to 5.08 cm (2") steel balls in a rotating cylinder.
2. Medium speed, roll-and-race or ball-and-race.
3. High speed, attrition or impact mills.

Generally, the pulverizers supply coal directly to the burners and load variations are accommodated by changing pulverizer load. An alternate system is the bin or storage system, in which the pulverized coal is stored before firing. The bin system allows less pulverizer capacity but requires pulverized storage capacity, additional feeders and venting systems, and a complex fire protection system. The direct-fired system is normally used today.

Burners are of three general types:

1. Turbulent - located in one furnace wall or opposed furnace walls.
2. Vertical - located in roof, firing down.
3. Tangential - located in furnace corners firing toward furnace center.

The furnace may be designed for dry ash removal with a hopper or water-screen bottom or for molten ash removal as in a slag tap furnace.

The furnace size requirement is dependent on the burning and ash characteristics of the coal as well as the firing system and type of furnace bottom. The general objectives are to provide control over ash deposition in the furnace and provide sufficient cooling so that ash entrained in the gases leaving the furnace is below the softening temperature before entering closely spaced convection sections.

C.3.5 Cyclone Firing

The cyclone furnace (Figure C-9) is a water-cooled horizontal cylinder in which fuel is fired, heat is released as extremely high rates, and combustion is completed. Its water-cooled surfaces are studded and covered with refractory chrome ore. Coal crushed in a simple crusher, so that approximately 95% will pass a 4-mesh screen, is introduced into the burner end of the cyclone. About 15% of the combustion air also tangentially enters the burner and imparts a whirling motion to the incoming coal. Secondary air with a velocity of approximately 91 m/sec (300 fps) is admitted in the same direction tangentially at the roof of the main barrel of the cyclone and imparts a further whirling or centrifugal action to the coal particles. The combustibles are burned from the fuel at volumetric heat release rates of $4.7\text{x}10^6$ to $8.8\text{x}10^6$ W/m^3 (450,000 to 800,000 Btu/ft^3·hr), and gas temperatures exceeding 1922 °K (3000 °F) are developed. These temperatures are

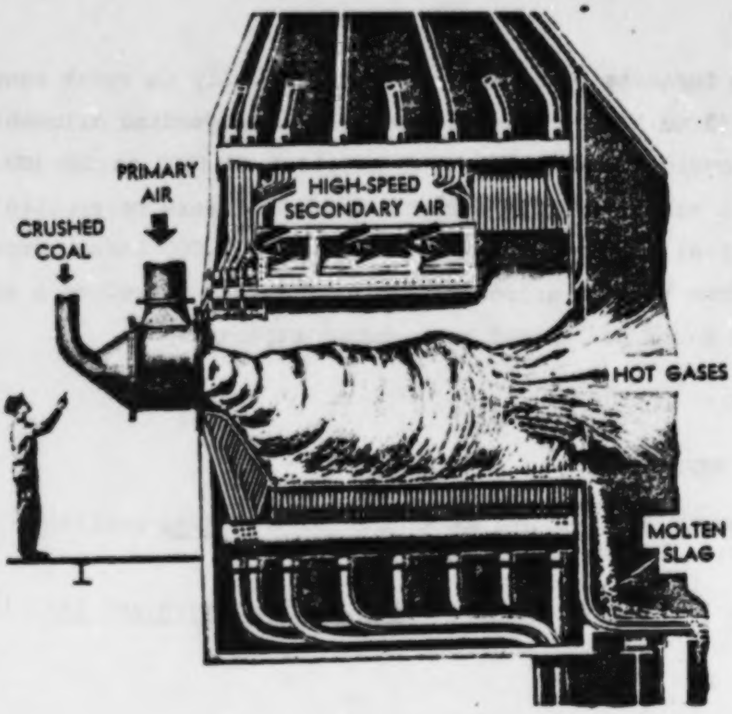


Figure C-9. Molten slag tap, water-cooled cyclone furnace (Ref. C-2).

sufficiently high to melt the ash into a liquid slag, which forms a layer on the walls of the cyclone. The incoming coal particles (except for a few fines which are burned in suspension) are thrown to the walls by centrifugal force, held in the slag, and scrubbed by the high-velocity tangential secondary air. Thus the air required to burn the coal is quickly supplied, and the products of combustion are rapidly removed.

The cyclone furnace is suitable for coal ash slag having a viscosity of 250 poises or less at 1700 °K (2600 °F). The volatile matter should exceed 15% on a dry basis to obtain the required high combustion rate. For coals of very high moisture content it may be necessary to limit the coal ash-softening temperature and slag viscosity to a lower value. An increase in combustion air temperature above a normal value of 589 °K (600 °F) will compensate to some extent for higher moisture content. Coals with too high sulfur content and/or a high iron ratio are not considered suitable.

Cyclone furnaces have been built commercially in sizes ranging from 1.52 to 3.05 m (5 to 10 ft) diameters with a corresponding allowable maximum heat input per cyclone furnace of 29.3 to 124.5 MW (100 to 425 MBtu/hr) respectively. A single cyclone furnace could therefore be applied to a minimum size industrial boiler generating 10.7 kg/s (85,000 lb/hr) steam. The load range is from full to approximately half load. Therefore a single cyclone furnace would be limited in turndown capacity.

REFERENCES FOR APPENDIX C

C-1 de Lorenzi, Otto (Ed.), Combustion Engineering, published by Combustion Engineering, Inc., 1955.

C-2 Babcock & Wilcox Company, Steam, Its Generation and Use, 1960.

APPENDIX D

CANDIDATE WESTERN COAL DEFINITION

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D.1 INTRODUCTION

Wyoming and Montana are the two largest western coal producing states. The geography of the western coal deposits dictates that these two states will be the most successful in supplying midwestern and eastern coal consumers at competitive prices to eastern coal. Therefore, the coal resources of these two states will be the focus of this appendix.

D.2 WYOMING

Wyoming has 495 billion metric tons of coal between 0 and 1,829 m (6,000 ft) of cover. This is 17% of the national total and ranks Wyoming first among the states in total coal resources. Of this resource, only 25%, or 124 billion metric tons, has been mapped and explored within 914 m (3,000 ft) of the land surface. Of that amount, approximately 2% is lignitic, 10% is bituminous, and 88% is subbituminous. One-half, or 62 billion metric tons, of the mapped resources is considered recoverable. Seventeen percent, or 22 billion metric tons, of the explored resources are classified as strippable. This strippable resource is greater than that of any other state and represents nearly 20% of the nation's known strippable coals. Of those 22 billion metric tons, 17 billion are termed recoverable and 13 billion of that are classed as reserves by today's standards. While almost 90% of Wyoming's strippable coals underlie the Powder River basin, the Hams Fork and Green River regions each contain over 4%. The remaining 1% to 2% of the resources lie in the Hanna field and Bighorn basin areas. A map showing active Wyoming coal mines is shown in Figure D-1.

The rank of Wyoming coal ranges from lignitic to high-volatile "A" bituminous. Lignite occupies a very small region in the northeastern part of the Powder River basin. Bituminous coal is restricted to the Black Hills region and portions of the Hanna field, Green River region, and Bighorn basin. High-volatile "B" and "A" bituminous coal is reported only in the Hams Fork region. Subbituminous coals are found in all major coal regions

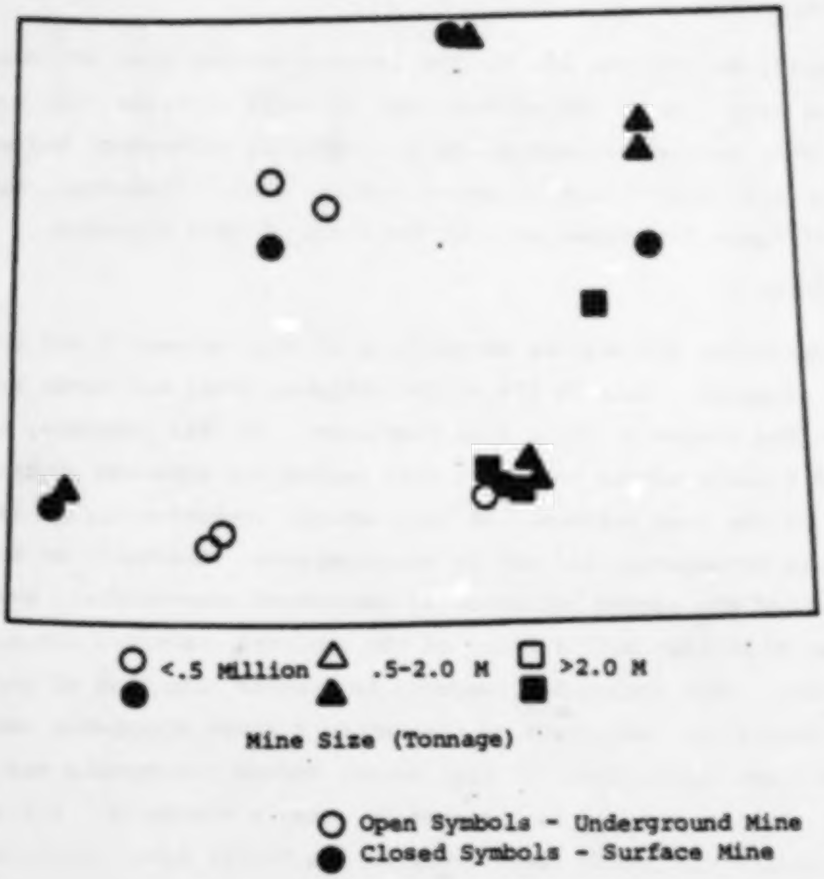
○ <.5 Million
△ .5-2.0 M
□ >2.0 M
Mine Size (Tonnage)
○ Open Symbols - Underground Mine
● Closed Symbols - Surface Mine

Figure D-1. Active Wyoming coal mines.

except the Black Hills region, and account for most of the state's resources and current production.

Typical Wyoming coal analyses exhibit the following ranges and averages:

As Received	Range	Seam Reserve Average
Moisture, %	1.7 - 32.8	14.2
Volatile Matter, %	32.0 - 46.0	39.0
Fixed Carbon, %	— —	41.0
Ash, %	1.4 - 17.5	5.2
Sulfur, %	0.2 - 5.0	0.7
Heating Value, MJ/kg (Btu/lb)	17.5 - 31.4 (7,500 - 13,500)	25.2 (10,850)

In terms of quality, coals with the lowest heating values, as well as the highest moisture and volatile contents, are found in the Powder River basin. The higher heating values are more prevalent in the western and southern portions of the state. Ash varies widely, with small isolated pockets of high-ash content (15% to 18%, dry basis) coals in the Powder River basin, Bighorn basin, and Hams Fork region. Sulfur contents are relatively low and variable. The southern and eastern parts of the Green River region contain some of the highest sulfur values. Overall, more than 99% of Wyoming's coal contains less than 1% sulfur and about one-half of that is less than 0.7% (as-received basis). Ninety-six percent of the strippable coals contain less than 1% sulfur, 3.5% is between 1% and 2%, and 0.5% is greater than 2% sulfur (as received).

There are 25 coal seams currently being mined in Wyoming. Surface-mined seams are between 1.83 and 36 m (6 and 118 ft) thick, but average 9.75 m (32 ftI. Seams mined underground range from 1.13 to 6.1 m (3.7 to 20 ft), averaging 2.6 m (8.5 ft). The thickest surface-mined seams occur in the Hams Fork region and Powder River basin. The latter basin also contains the nation's, and perhaps the world's, thickest seam of 67 m (220 ft).

Table D-1 contains a listing of the active mines in Wyoming and Montana. Also shown are the estimated reserves, estimated useful life, and current 1973 and 1974 production of the mines.

The coal analyses of the 14 largest mines in Wyoming and Montana are presented in Table D-2.

TABLE D-1. COAL CANDIDATES FOR TESTING (ACTIVE MINES)

Company	Mine	Reserves	Life (yrs)	Current Production (Mill. Metric Tons/Year) 1973	1974
MONTANA:					
Westmoreland	Sarpy Creek	1500 MT	100	4.00	--
Decker	Decker No. 1	2240 MT	30	4.15	6.79
Peabody	Big Sky	---	---	1.97	2.23
Western Energy	Colstrip	1440 MT	50	4.25	3.21
WYOMING:					
Amax	Belle Ayr	18,500MT	50	0.89	3.30
Wyodak	Wyodak			0.75	--
Arch Mineral	Seminoe 1	305 MT	15	2.87	3.14
	Seminoe 2			1.50	2.59
Rosebud	Rosebud			1.51	1.96
Kemmerer	Ekol	1679.9MT	100	0.40	--
	Sorenson		60	2.55	2.44
Bighorn	Bighorn		15	0.45	--
Energy Development					
Pacific Pwr & Light	Dave Johnston		35	2.90	2.7
	Jim Bridger		35	--	--

Sulfur content of the Wyoming coal produced by these mines is all well below 1% and the heating value is generally around 23.3 MJ/kg (10,000 Btu/lb). The ash softening temperature (reducing atmosphere) of these coals

TABLE D-2. COAL ANALYSES OF THE FOURTEEN LARGEST MINES IN WYOMING AND MONTANA

MINE	SEAM	Moisture (%)	Volatiles (%)	Fixed Carbon (%)	Ash (%)	Sulfur (%)	MJ/kg (Btu/lb) As Received	MJ/kg (Btu/lb) Dry	Ash Softening Temperature °K (°F)	Free Swelling	Hardgrove Grindability Index
WYOMING											
Belle Ayr	Smith-Roland	28.06	29.06	30.47	5.10	0.29	18.2 (7,021)	26.2 (11,237	1,410 (2,078)	N.A.	53.28
Wyodak	Smith-Roland	28.13	31.63	34.32	5.90	0.52	19.4 (8,332)	26.7 (11,470)	1,522 (2,280)	N.A.	54.0
Seminoe 1	Bed No. 25	13.96	---	---	6.98	0.37	23.2 (10,000)	----	----	---	---
Seminoe 2	Hanna No. 2	11.5	42.6	39.3	6.6	0.4	25.3 (10,890)	----	----	N.A.	---
Rosebud	No. 80 & 82 Bed	14.20	35.03	42.56	8.11	1.0	23.9 (10,300)	28.4 (12,200)	1,483 (2,210)	N.A.	58.0
Sorenson & Ekol	Adaville	20.2	42.3	53.4	4.3	0.9	23.4 (10,080)	28.6 (12,620)	1,594 (2,410)	N.A.	58.0
Bighorn	Armstrong & Monarch	23.85	32.35	38.49	5.30	0.61	21.6 (9,300)	---- (2,140)	1,444	N.A.	45.6
Energy Development	Bed 65	11.6	---	---	7.1	0.7	25.6 (11,020)	----	----	---	---
	Brooke	13.66	---	---	6.5	0.45	25.1 (10,806)	----	----	---	---
Dave Johnston	School	24.12	39.89	17.75	18.24	0.33	16.4 (7,070)	21.7 (9,317)	----	0.5	48.3
Jim Bridger	Deadman	20.52	29.09	40.71	9.68	0.47	21.3 (9,150)	----	----	---	---
MONTANA											
Sarpy Creek	Rosebud-McKay Robinson	2.	29.	37.	9.	0.73	19.6 (8,450)	----	1,456 (2,161)	N.A.	56.
Big Sky	Rosebud-McKay	26.5	29.11	34.5	9.89	1.31	19.4 (8,360)	30.6 (13,134)	1,490 (2,222)	N.A.	51.6
Decker No. 1	Dietz	23.	34.	39.3	3.7	0.4	22.3 (9,600)	28.7 (12,320)	1,505 (2,250)	N.A.	52.
Colstrip	Rosebud	25.5	27.72	38.33	8.45	0.8	20.3 (8,750)	----	1,505 (2,250)	N.A.	---

* MAF = Mineral matter and ash free;
N.A. = Non-agglomerating coals

varies somewhat from seam to seam but is generally around 1500 °K (2150 °F). Grindability of the coals as measured by the Hardgrove Index indicates that they are slightly harder to grind than comparable eastern coals. The Hardgrove Index ranges from 0 to 100 with 100 representing good grindability. Therefore the lower the Hardgrove Index number, the more difficult the coal is to grind. This poorer grindability will have an effect on the performance of coal pulverizing mills in pulverized-coal-fired units. The Hardgrove Index, however, does not give a true representative indication of the western coals grindability as received,since the coal must be air dried prior to performing the test. The higher moisture content of western coals requires higher air temperature in the pulverizer to improve grinding performance.

Montana

Figure D-2 depicts the geographical areas of Montana coal fields. The Fort Union region of eastern Montana is presently the focus of major development. The interest in this area is expected to continue for the foreseeable future. Estimates place the strippable coal in this region at more than 38 billion metric tons. Table D-3 gives the name of the field, the coal bed, thickness, estimated reserves, average tons/acre, ash, sulfur, and Btu. Although coal is present in other parts of the state, it is of less significance because recovery would require deep mine methods.

Characteristics of the topography and the thickness of the Fort Union coal beds make possible the mining of large quantities of coal from relatively small, compact areas, which facilitate reclamation. Coal beds 7.6 - 18 m (25 to 60 ft) thick are not uncommon, and in the Decker area, the coal in a single bed reaches a thickness of 24 m (80 ft). Matson and Blumer (Ref. D-1) have surveyed southeastern Montana and analyzed 32 coal deposits; proximate analyses, forms of sulfur, calorific values, and major ash constituents of the coal samples are included.

Currently, only five companies. are producing coal from the Fort Union beds of eastern Montana. They are:

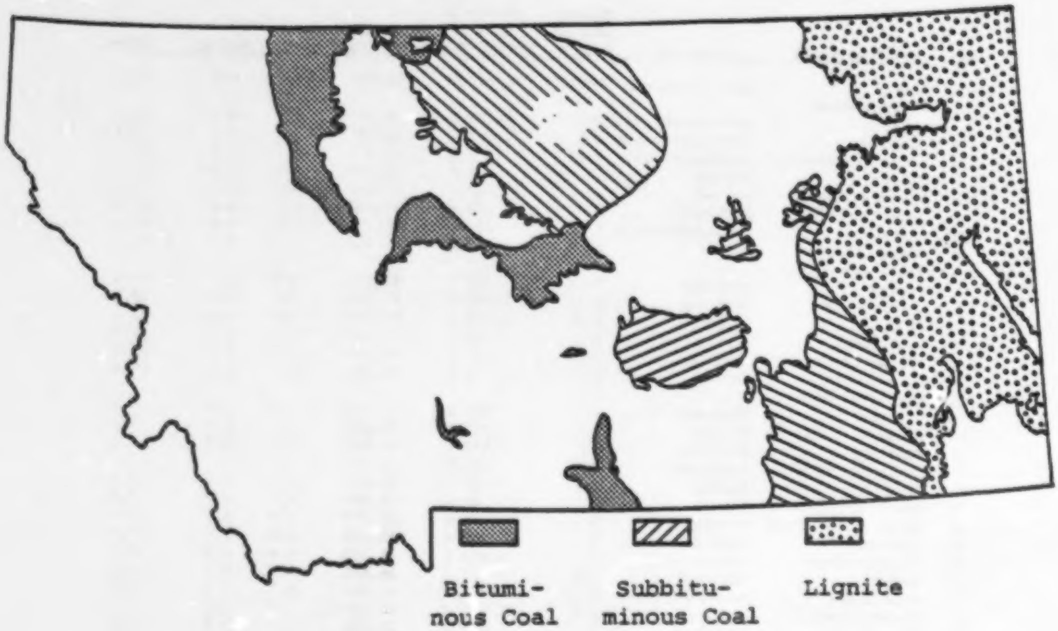
Bituminous Coal
Subbituminous Coal
Lignite

Figure D-2 . Index map of Montana coal fields.

TABLE D-3. STRIPPABLE SUBBITUMINOUS AND LIGNITE COAL FIELDS, EASTERN MONTANA

No. of Map	Name of Field	Coal Bed	Thickness in Meters	Estimated* Reserves in M of Metric Tons	Average Tons/Acre	Ash †	Sulfur †	MJ/kg
1	Decker	Anderson-Deitz	6-27	1,947 F	76,435	4.0	0.4	22.4
2	Hanging Woman Creek	Anderson-Deitz	3-11	3,099 G	38,625	6.4	0.3	19.6
3	Moorhead	Anderson-Canyon	2-9	1,089 G	40,005	5.3	0.3	19.3
4	Poker Jim Lookout	Anderson-Deitz	4-18	573 G	67,825	5.7	0.4	18.1
5	Roland	Roland	3	315 F	17,700	5.6	0.3	17.7
6	Squirrel Creek	Roland	3	130 F	17,800	5.6	0.3	17.7
7	Upper Rosebud	Anderson	6	220 F	35,400	4.4	0.4	19.5
8	Birney	Brewster-Arnold	5	321 G	26,470	5.9	4.4	20.6
9	Canyon Creek	Wall	9-18	200 F	70,800	4.6	0.3	21.1
10	Poker Jim-O'Dell Creek	Knoblock	3-12	770 G	47,825	4.9	0.3	20.6
11	Otter Creek	Knoblock	6-20	1,041 G	51,290	4.7	0.4	19.7
12	Ashland	Knoblock	6-30	2,595 G	95,000	4.8	0.2	21.8
13	Cook Creek	Sawyer	2-4	53 F	17,700	5.1	0.7	18.4
14	Beaver Creek	Knoblock	3-7	160 F	30,030	7.0	0.5	18.9
15	Liscom Creek	Knoblock	2	75 F	14,160	8.7	0.6	18.4
16	Greenleaf-Miller Creek	Knoblock	3-6	260 F	32,655	7.8	0.8	19.5
17	Sweeny-Snyder	Terret	5	312 G	29,650	5.8	0.7	19.0
18	Colstrip	Rosebud	6	1,440 G	43,835	8.4	0.7	20.2
19	Carpenter Creek	Carpenter	1-2	50 F	14,015			
20	Fire Creek	Pawnee	5-7	40 G	31,870	6.0	0.4	17.8
21	Upper Cache Creek	Pawnee	6	40 G	35,400	6.0	0.4	17.8
22	Lower Cache Creek	Broadus	4	10 G	21,275	7.2	0.3	17.3
23	Sonnette	Pawnee	6	206 G	35,400	6.6	0.7	17.0
24	Pumpkin Creek	Sawyer	9	1,900 G	45,315	7.9	0.5	17.3
25	Broadus	Broadus	1-8	737 G	38,985	7.2	0.3	17.3
26	Sand Creek	Knoblock	5-11	278 G	46,660	6.7	0.3	17.1
27	Foster Creek	Knoblock	2-5	1,200 G	20,690	7.7	0.5	17.7
28	Pine Hills	Dominy	5	280 G	30,950	7.2	0.5	16.9
29	Lame Jones	Dominy	2-3	150 R	14,160			14.0
30	Lamesteer	Harmon(?)	2-3	35 R	17,700			14.7
31	Wilbaux	C	2-12	643 G	34,720	7.9	0.9	14.1
32	Little Beaver	C	2-5	134 R	15,865			
33	Four Buttes	C	2-6	91 G	17,570			14.3
34	Hodges		2-3	10 R	12,390			
35	Griffith Creek		2-4	10 R	17,800			
36	Smith-Dry Creek	G	2-4	150 R	17,700			
37	O'Brian-Alkali Creek		2-4	150 R	17,700			
38	Breezy Flat	Pust		200 F	30,090	6.7	0.5	15.1
39	Burns Creek	Pust	4-6	200 R	30,090			
40	N.F. Thirtden Mile Crk.	Pust	2-13	225 F	44,250			16.0
41	Fox Lake	Pust	2-5	46 F	21,240			16.0
42	Lane	Lane	2	541 R	12,390			16.6
43	Carroll	Carroll	2	345 R	11,584	5.5	0.3	17.2
44	Redwater River	S	3-6	642 G	26,550	6.1	0.4	17.2
45	Weldon-Timber Creek	S	2-6	724 G	28,320			17.8
46	Fort Kipp	Ft.Kipp-Ft.Peck	2-3	331 G	22,830	4.6	0.2	14.2
47	Lanark	Lanark	3	100 G	12,390	6.3	0.4	15.9
48	Medicine Lake		3	58 F	15,510	7.2	1.0	16.0
49	Reserve		3	246 F	13,495	7.6	0.4	15.3
50	Coal Ridge	Coal Ridge	3	1 150 F	17,700	7.5	0.4	13.5
51	Sarpy Creek	Rosebud-McKay	3-10	1,500 F	35,400	6.5	0.5	20.0
52	East Moorhead	Cache	3-10	541 G	33,850	7.2	0.5	16.6
53	Knowlton	Dominy	3-11	798 G	52,030	4.1	0.4	15.5
54	Cheyenne Meadows	Knoblock	11-22	1,200 G	88,500	1	0.4	19.5
55	Charter	Mammoth	2-6	60 G	17,700			

* "As received basis (where more than one sample availablc. Figures are averages) Source Montana Bureau of Mines and Geology.

†(G, good; F, fair; R, rough)

Knife River Coal Co. has an average annual production of slightly over 300,000 metric tons of lignite coal with a heat content of 15.2 MJ/kg (6,520 Btu/lb) and a sulfur content of 0.5%. This mine is dedicated to the Montana-Dakota Utilities Co. power plant at Sidney, MT.

Western Energy Co. is a wholly-owned subsidiary of Montana Power Co. with operations at Colstrip. Coal analyses are given in Table D-2.

Decker Coal Co. is a joint venture between Pacific Power and Light and Peter Kiewit Sons' Co.; the latter being the operating partner. Table D-2 gives coal analyses for this company.

Peabody Coal Co. is currently mining over 1.5 million metric tons annually from the Rosebud and McKay beds near Colstrip, MT. Unit trains haul coal 800 miles to Cohassett, MN for Minnesota Power and Light.

Westmoreland Resources is a Montana-based partnership owned by Kewanee Oil Co., Penn Virginia Corp., Morrison-Knudsen Co., Inc., and Westmoreland Coal Co. Westmoreland's operations are located at Sarpy Creek, MT. Westmoreland ships coal to five midwest utilities:

- Northern States Power Co., Minneapolis, MN
- Wisconsin Power and Light, Madison, WI
- Dairyland Power Cooperative, LaCrosse, WI
- Interstate Power Company, Dubuque, IA
- Central Illinois Light Company, Peoria, IL

The coal analyses of the four producing mines in Montana from Table D-2 show somewhat higher sulfur content (0.8% average), and lower heat value (19.8 MJ/kg average) than Wyoming coals. It is this combination that could make Montana coals of marginal value for reducing sulfur below the 520 ng/J (1.2 lb SO_2/MBtu) regulation. Ash softening temperaures and Hardgrove grindability are comparable to Wyoming coals.

Coal analyses for the 14 largest mines in Montana and Wyoming are presented in Table D-2. They are representative of approximately 95% of the projected coal production capacity from these two western states through 1983. The use of any one of these coals in the test program would be valid based on the ability of that mine to produce coal at better than present production levels through 1983. However, all mines listed in the table have expansion plans. Most mines project a doubling of present production by 1980 and some, such as Westmoreland Resources, expect to increase production by a factor of five by 1982.

REFERENCES FOR APPENDIX D

D-1 Matson, R. E. and Blumer, J. W., "Quality and Reserves of Strippable Coal, Selected Deposits, Southeastern Montana," Montana Bureau of Mines and Geology Bulletin 91, December 1973.

APPENDIX E

EXAMINATION OF SUPPLY VARIABLES OF SPECIFIC WESTERN COALS

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E.1 INTRODUCTION

Availability, mining and transportation costs determine the price that must be ultimately paid by a user of western coal. Coals with desirable properties such as relative high heating value and low sulfur content demand a higher price as do coals in limited supply. Prices at the mine are also subject to several factors including type of mining operation, storage and handling facilities and the extent to which the coal is processed. Variables affecting transportation cost are size and frequency of shipment and location of user with respect to existing transport facilities.

The data presenting the current production from the mines in Montana and Wyoming are presented in Table D-1 (Appendix D), along with projections of future expansion.

Table E-1 gives the average value per ton of bituminous and lignite coals at the mine for 1971 and 1972. Note that strip mining costs per ton had risen from $1.79 to $2.01 in Montana and from $3.35 to $3.69 in Wyoming or approximately 10%. Projected cost to maintain and expand future production are considered confidential by the mine operators and therefore were not made available for this study. Additional increases beyond the 10% annual rate were expected for 1973, 1974 and beyond due to inflationary pressures.

Transportation costs have the greatest influence on western coal prices to potential users in the midwest due to the long distances involved. The only feasible means of transporting western coal to users and to distribution centers in the midwest is by rail. No other alternative exists. Once the coal reaches the Great Lakes or Mississippi River, water transportation systems become available. Early transfer to waterway shipment is preferred over all-rail transport since the cost is lower.

TABLE E-1. AVERAGE VALUE PER TON, F.O.B. OF BITUMINOUS AND LIGNITE PRODUCED, BY DISTRICT

District	1971				1972			
	Underground	Strip	Auger	Total	Underground	Strip	Auger	Total
1. Eastern Pennsylvania	$10.08	$6.49	$6.28	$8.12	$9.60	$6.92	$8.06	$8.23
2. Western Pennsylvania	9.53	6.09	5.61	8.78	10.79	6.38	5.34	9.93
3. Northern West Virginia	7.73	6.12	5.32	7.36	8.55	6.64	6.36	8.16
4. Ohio	6.75	4.76	4.35	5.24	7.41	5.29	4.69	5.96
5. Michigan	..	..	--	..	..	..	..	..
6. Panhandle	6.60	4.56	..	6.55	7.51	6.50	6.50	7.49
7. Southern Numbered 1	13.82	10.22	10.02	12.21	14.87	11.40	11.86	14.45
8. Southern Numbered 2	9.22	6.31	6.67	8.18	10.19	6.41	6.47	8.86
9. West Kentucky	5.46	4.50	5.25	4.82	5.97	4.81	5.64	5.23
10. Illinois	5.96	4.95	--	5.46	6.82	5.49	--	6.14
11. Indiana	6.01	5.05	--	5.18	6.62	5.51	--	5.58
12. Iowa	4.82	4.54	..	4.86	4.80	4.91	..	4.86
13. Southeastern	11.30	5.82	5.05	7.97	13.40	6.93	6.18	9.43
14. Arkansas-Oklahoma	13.99	9.13	8.50	10.53	14.79	8.37	--	9.04
15. Southwestern	..	5.16	--	5.16	..	4.86	--	4.86
16. Northern Colorado	5.25	..	--	5.25	5.17	..	--	5.17
17. Southern Colorado	6.18	3.97	--	6.71	9.46	4.11	--	7.25
18. New Mexico	..	2.62	..	2.62	..	2.68	--	2.68
19. Wyoming	6.25	3.35	2.20	3.39	4.89	3.69	--	3.74
20. Utah	7.37	8.00	--	7.37	8.93	8.00	--	8.93
21. North-South Dakota	..	1.91	--	1.91	..	2.02	--	2.02
22. Montana	9.22	1.79	--	1.82	9.74	2.01	--	2.08
23. Washington	13.55	7.16	--	7.27	16.40	6.99	--	7.07
Total	8.87	5.19	6.37	7.07	9.70	5.48	6.54	7.66

E.2 RAIL TRANSPORTATION

Existing rail lines of three major carriers service the Montana-Wyoming coal fields. The Burlington Northern (BN) has extensive rail connections in both states that transport coal from the Powder River basin along main line connections to several key distribution points. Existing mining operations along the main line of the Union Pacific (UP) through southern Wyoming ship coal to Omaha and Kansas City. Tracks of the Chicago and Northwestern Railroad (C&NW) extend into the Powder River basin in eastern Wyoming with existing facilities that generally split the BN and UP systems to the Great Lakes. Several joint ventures between the UP and C&NW are under way to deliver southern Wyoming coal to the Minnesota, Wisconsin, and Chicago areas.

Figure E-1 presents a geographical distribution of the various types of coals employed in the operations of the firms questioned during this study. Western coal is available at reasonable shipping costs to users along major rail connections to the west. The coal is also transferred from existing rail to river barges for distribution along the Mississippi River and from rail to lake barge in Duluth to allow transport to other Great Lakes ports.

No additional main line connections are planned for western coal shipments; however, some trace extensions and improvements have been deemed necessary. A 187 km (116-mile) trace connecting the main lines of the BN and the C&NW has been proposed jointly by the two railroads to open up the central Powder River basin. Also planned for the C&NW is a complete upgrading of the main lines from Shawnee, Wyoming, to Freemont, Nebraska. Extensive additions and improvements to the coal-handling equipment have also been undertaken.

E.3 UNIT TRAIN OPERATION

Currently the most economical means of transporting western coal to midwestern markets is by unit train. A unit train is a set of locomotives and

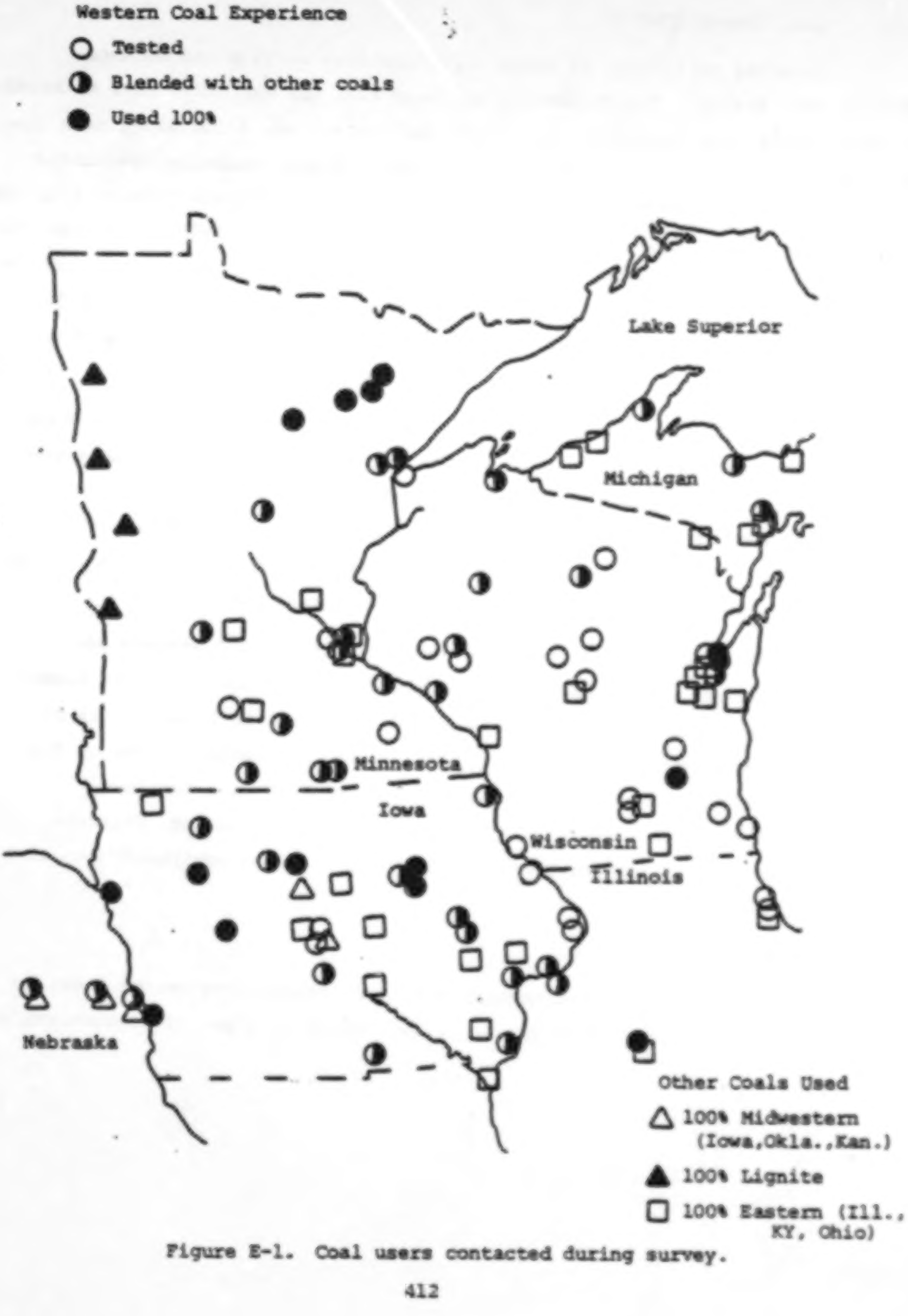
Western Coal Experience
○ Tested
◑ Blended with other coals
● Used 100%
Lake Superior
Michigan
Minnesota
Iowa
Wisconsin
Illinois
Nebraska
Other Coals Used
△ 100% Midwestern (Iowa,Okla.,Kan.)
▲ 100% Lignite
□ 100% Eastern (Ill., KY, Ohio)

Figure E-1. Coal users contacted during survey.

cars that operate in a continuous cycle from one origin to one destination and return. Techniques and equipment are now in use that have made the widespread use of western coal possible. The continued application of the unit train is a key factor in future western coal shipments.

Loading is generally accomplished by a high-speed conveyor system. The coal is carried to a storage bin located at the top of a tipple and loaded into the train as it moves continuously underneath. A typical loading operation of 100 cars can be completed in approximately four hours.

The trains are multiple engine powered with the diesels generally separated into two groups. The lead diesel, located in a group in the front of the train, is manually operated and transmits commands to the other group of engines located near the middle. The purpose of this group is to spread the tractive efforts through the train so that the draw bar pull on the front car is not excessive. Problems due to the extremely heavy trailing weights are also significantly diminished. The locomotive arrangement also helps in overcoming potential brakeline air pressure losses which is a serious problem in the operation of long trains. Stops during long hauls are limited to routine maintenance and inspection.

The unloading process is accomplished by the use of either rotary or bottom dumping cars. Rotary dumpers are equipped with swivel couplings so that each car can be rotated about the coupling without being detached from the train. Significant improvements to coupling designs and positioners have greatly reduced unloading times. Bottom dump cars with specially designed hoppers for fast unloading are employed with shakers or vibrators for complete discharge. Unloading of an entire train to storage facilities or water transportation can usually be accomplished in under four hours.

The unloaded coal is stored in conical piles or in bins and silos. Covered storage is usually preferred due to the protection from the weather and reduced handling costs; however, the increased initial capital investment is higher than with open storage. The key factor in ground storage is to make it possible to recover as much of the coal as possible with the minimum aount of handling. Problems are also encountered with unsightly and dusty open storage conditions in metropolitan areas.

Improvements in unit train performance are being made by the use of advanced car designs and materials, along with better scheduling of equipment, employment and maintenance. The regions of long-distance hauling have required modifications to the dynamic braking system and coupling devices. Coal hopper cars are larger, 100 ton vs. 70 ton, and equipped with automatic door opening and closing devices or swivel couples for rapid unloading. It is estimated that an additional 2800 new large coal hopper cars will be needed to haul western coal once full production is met. Periodic inspections and maintenance are conducted ar regular intervals (usually 800 km) for safety and improved mechanical reliability.

While the continued improvement of unit train operation has allowed railroads to hold shipping rates down, current inflationary pressures are requiring adjustments to shipping costs. The primary factors affecting these costs are labor and materials. Rates over a particular route are determined through negotiations between the railroad and the receiver. These rates are periodically adjusted based on a mechanism established during negotiations. These rate adjustments are usually based on the Index of Railroad, Material Prices and Wage Rates of the Association of American Railroads.

Current unit train shipments involving the BN, UP and C&NW are outlined in Table E-2. Listed are the location (mine) of origin, destination (user), 1974 shipment volume and the rates as of March 1, 1975. In all cases, shipments are made directly to utilities and are primarily used in boilers of greater than 38 kg/s (300,000 lbs steam/hr). As illustrated in Table E-2, shipping rates range from $3.43 per net ton, (17¢/$10^6$ Btu) for delivery in Sergeant's Bluff, Iowa, to almost $9.00 per net ton (45¢/$10^6$ Btu) for receipt in Hammond, Indiana.

In addition to unit train deliveries, several hundred cars per month are moved from the western coal fields to the midwest in single and multiple car shipments, and in entire train loads on a non-unit train operation. These shipments generally go to paper companies, industrial concerns and small utilities in Iowa, Wisconsin and Minnesota.

TABLE E-2. UNIT TRAIN SHIPMENTS OF WESTERN COAL

From	To	Approximate 1974 Volume in Tons	Rate as of March 1, 1975		Carrier
			cents/net ton	cents/MBtu	
Hanna, Wyoming (Arch Minerals)	Oak Creek, Wisconsin (Wisconsin Electric Power)	750,000	690	35	UP-CNW
Hanna, Wyoming	Omaha, Nebraska (Omaha Public Power)	500,000	594	30	UP
Hanna, Wyoming (Energy Dev. Corp)	Sergeant Bluff, Iowa (Iowa Public Service)	1,100,000	343	17	UP-CNW
Hanna, Wyoming	Council Bluffs, Iowa (Iowa Power & Light)	220,000	650	33	UP
Hanna, Wyoming (Arch Minerals)	Waukegan, Illinois (Commonwealth Edison)	2,800,000	774	39	UP-CNW
Hanna, Wyoming (Arch Minerals)	Hammond, Indiana (No. Indiana Pub Serv)	1,550,000	887	45	UP-CNW
Hanna, Wyoming (Arch Minerals)	Kansas City, Missouri (Kansas City P & L)	800,000	374	19	UP
Colstrip, Montana (Western Energy Co)	Chicago, Illinois (Commonwealth Edison)				BN
Colstrip, Montana (Western Energy Co)	Becker, Minnesota (Northern States Power)		Proposed for 1976		BN
Decker, Montana (Decker Coal Co)	Superior, Wisconsin (Distribution in the Detroit Edison system)	1,000,000			BN
Colstrip, Montana (Western Energy Co)	Portage, Wisconsin (Wisconsin P & L)	2,000,000	530	30	BN
Decker, Montana (Decker Coal Co)	Havana, Illinois (Commonwealth Edison)	4,500,000			BN-C&IM
Sarpy Creek, Montana (Westmoreland)	St. Paul, Minnesota (NSP and others)		Proposed for 1976		BN

(continued)

TABLE E-2 (continued).

From	To	Approximate 1974 Volume in Tons	Rate as of March 1, 1975		Carrier
			cents/net ton	cents/MBtu	
Sarpy Creek, Montana (Westmoreland)	Madison, Wisconsin (Wisconsin Power & Light)	Current total shipments of 4,000,000 TPY			BN
Sarpy Creek, Montana (Westmoreland)	Alma, Wisconsin (Dairyland Power Coop)				BN
Sarpy Creek, Montana (Westmoreland)	Dubuque, Iowa (Interstate Power Co)				BN
Sarpy Creek, Montana (Westmoreland)	Peoria, Illinois (Central Illinois Light)				BN
Sarpy Creek, Montana (Westmoreland)	Minneapolis, Minnesota (Northern States Power)				BN
Colstrip, Montana (Peabody Coal Co)	Cohassett, Minnesota (Minnesota Power & Light)	1,500,000			BN
Belle Ayr, Wyoming (Amax Coal Co)	Cason, Texas (Southwestern Elec Pwr)	1,750,000			BN-KCS
Belle Ayr, Wyoming (Amax Coal Co)	St. Louis, Missouri (Distribution in the American Electric Power System)	2,000,000			BN

Shipping rates for non-unit train deliveries as supplied by Burlington Northern demonstrate the dramatic cost increases that must be absorbed by the small users. The tariff from Colstrip, MT, to Minneapolis, MN on shipments of train load lots on a single line haul not under unit train operation is $5.55 per net ton (p.n.t.), while a single car shipment is $9.03 p.n.t. Similarly in the UP system, unit train deliveries from Hanna, WY to Kansas City, MO are shipped for $3.74 p.n.t., while lot deliveries of 1,500 tons cost $7.99 p.n.t. A typical western coal tariff is presented in Table E-3.

Multiple line haul deliveries are even more expensive. For example, the proposed unit train tariff from Colstrip to Columbia, WI, via the BN and C&NW is $5.30, while a single car delivery to the same area is $13.12, or 148% higher.

The above shipping costs point out the problem facing small users of western coal. Unit train operation for large users (primarily utilities), has allowed shipping costs, and therefore total cost, of western coal to become competitive with the traditional bituminous coal suppliers in the east and midwest. In order to make western coal more attractive to non-utility users, a method must be found to incorporate the unit train concept into the small user's supply system.

E.4 RAIL-TO-WATER TRANSFER FACILITIES AND DISTRIBUTION CENTERS

The concept of a central distribution center supplied by unit trains and feeding several users has been proposed. All of these facilities will be used initially to supply a large utility and will be in conjunction with a rail-to-water transfer system. Since many present coal users are supplied from traditional sources in Illinois and Kentucky by water, the importance of this transfer is obvious. Currently, western coal supply/distribution centers are planned or under construction in the Duluty, Minneapolis, and St. Louis areas.

TABLE E-3. WESTERN COAL TARIFF FOR LOCAL, JOINT, AND PROPORTIONAL RATES
BURLINGTON NORTHERN, INC.
Effective April 8, 1975

SECTION 1
SPECIFIC RATES IN CENTS PER 2,000 LBS
(For application, see page 22 of tariff)

ITEM	COMMODITY, CARLOADS	APPLICATION		RATES
		FROM	TO	
Ⓔ 200-F	BITUMINOUS COAL. In open top cars. Minimum weight marked capacity of car, except when loaded to full visible capacity, actual weight will apply. (ML A-8696)	Colstrip . . . . MT	Ames . . . . IA	② 1044
			Austin. . . . MN	②④⑥ 1000
			Burlington . . IA	① 1049
			Cedar Falls . IA	②⑤ 1029
			Cedar Rapids . IA	②④⑤⑥ 1044
			Clinton . . . IA	① 1029
			Corn Belt . . IA	④⑥ 1044
			Davenport . . IA	① 1029
			Dubuque. . . IA	①④⑥ 1029
			Eau Claire . . WI	②③④⑥ 1000
			Humbolt. . . IA	② 1044
			Iowana . . . IA	① 1029
			Menasha . . . WI	③④ 1312
			Milwaukee . . WI	②③④⑥ 1312
			Muscatine . . IA	④⑤⑥ 1029
			Neenah . . . WI	③④⑥ 1312
			Neenah-Menasha WI	② 1312
			Rochester . . MN	② 1000
			Spencer . . . IA	②④⑥ 1044
			Waterloo . . IA	②⑤ 1044
			Waupun . . . WI	④⑥ 1312

Route via:

① BN-direct.
② BN-Minneapolis, MN-CNW.
③ BN-Minneapolis, MN-SOO.
④ BN-St Paul, MN-MILW.
⑤ BN-St Paul, MN-RI.
⑥ BN-Miles City, MT-MILW.
Ⓔ Expires as indicated in Item 150.

A rail-to-ship coal handling facility is currently under construction in Superior, Wisconsin, to handle western coal shipments to Detroit Edison that will result in a 40-50% reduction in all rail shipping costs through Chicago. Initially, this facility will handle 8,000,000 tons per year of Decker coal to Detroit Edison delivered by unit trains on the Burlington Northern, and Chicago and Northwestern systems. An additional 6,000,000 tons per year capacity that is as yet uncommitted will be available for other users.

The C. Reise Coal Company, who will have joint ownership of this facility, is planning an additional facility to handle primarily smaller customers in train load lots of 50 cars on a non-unit train operation from the Peter Kewitt operations at the Big Horn and Rosebud Mines. Significant shipping cost reductions will be realized from single car deliveries. The coal will be loaded on to lake barges to distribution to customers along the Great Lakes. It may prove feasible to subsequently transfer the coal from lake barge to other surface transportation for delivery to user.

A plan for a coal wharf to store and transfer coal from trains to river barges has been proposed for the Minneapolis-St. Paul area. The facility, commonly called "Pig's Eye", will be supplied by unit trains along the Burlington Northern, and Chicago and Northwestern Railroads from the Sarpy Creek Mine in Montana. The facility is primarily designed for use by Northern States Power, Dairyland Cooperative, Interstate Power Company, and Wisconsin Power and Light. However, storage and transfer facilities for smaller users have been planned. The facility will handle approximately 5,000,000 tons of coal per year.

Currently the coal wharf project has not been approved by the State of Minnesota due to environmental concerns. Arguments against the facility include unsightly conditions, dust and noise. Several proposals to improve the situation including a possible dome to cover the facility, have been made. None has yet been approved. Without this facility, future expansion of western coal to small users in the Minnesota-Wisconsin area is in serious jeopardy.

Four other rail-to-river facilities are currently proposed or under construction in the St. Louis area. A 10,000,000-ton facility in Metropolis, Illinois, is under construction. This will be for the sole use of the American Electric Power Company, a holding company that consists of several utilities in Ohio, Michigan, West Virginia, and Tennessee. Coal will be delivered by unit trains from Wyoming and Utah by the Burlington Northern and Missouri Pacific Railroads. This facility may eventually expand to 20 million tons per year.

A facility initially designed for industrial users has been proposed for the Tri Cities Regional Port District. Again, deliveries will be made by unit train, stockpiled, and supplied to users either by river barge using existing port facilities or by truck. The initial capacity for the facility is 2-3 million tons per year but may go as high as 15 million tons.

An existing rail-to-water facility in St. Louis operated by the Peabody Coal Company has been employed to transfer coal to the American Electric Power Company for test purposes. Once the Metropolis, Illinois, facility is completed, this may be available for unit train delivery and storage for non-utility users.

Another planned operation to be developed by the American Commercial Barge Company similar to the Pig's Eye coal wharf has been proposed for the St. Louis area. Initially, this would be employed for shipments to utilities in the lower Mississippi River. Like the St. Paul facility, this project is meeting resistance from environmental groups and has been forced to alter locations. This operation, once approved, will have a capacity of between 10 and 20 million tons per year, the portion of which will be available for small users is as yet undetermined.

E.5 LAKE AND RIVER TRANSPORTATION

The lower transportation costs and existing coal-handling facilities make an early transfer to waterway shipment preferred over an all-rail shipment. The existing inland waterway system composed of the Mississippi and Ohio Rivers and the Great Lakes provides an excellent means of transporting western coal to potential domestic markets.

E.6 CONCLUSION

Estimates are that the present 50 million tons annual output of western coal will increase to 250 million tons annually. The coal reserves and technology required to mine it are presently available. Adequate rail and water transportation facilities exist to transport the western coal to potential domestic users. The development of rail-to-water transfer facilities, distribution centers, and additional transportation equipment are the key elements in future expansion of western coal use. In order for this expansion to occur, a favorable economic climate must exist that will encourage the development of this coal on a long-term basis.